Report EP 77-1

Oil and Natural Gas Resources of Canada 1976

Energy, Mines and Resources Canada
Énergie, Mines et Ressources Canada

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OIL AND NATURAL GAS RESOURCES OF CANADA, 1976

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FOREWORD

Canadian consumption of oil and natural gas, on a per capita basis, is among the highest in the world. Oil and gas supply almost two thirds of our total present-day energy requirements and forecasts of the Department of Energy, Mines and Resources indicate that this pattern is not likely to alter substantially during the next 15 years.

While Canada's proved reserves of conventional oil continue to decline and our future supplies of oil and natural gas grow ever more costly, Canadian demand for these energy forms continues to increase. The growing gap between our energy requirements and our ability to meet these demands from domestic sources suggests that we could become increasingly dependent on the rest of the world, and on the Organization of Petroleum Exporting Countries in particular, for our future oil supplies. This prospect carries with it economic and political risks which the Government of Canada views with concern. Increased exploration and development for oil and gas and an increased flow of resource information to the public are two of the strategy elements of *An Energy Strategy for Canada* issued earlier this year. They are counter measures to offset these risks. This report is a contribution to these strategy elements.

Policies and decisions involved in the stewardship of the nation's resources must be based on the best possible knowledge of the resource distribution in Canada. This knowledge must provide answers to questions regarding the magnitude, regional distribution and quality of the resources and include some measure of the reliability of the answers. For most of these questions the "real" answers are surrounded by uncertainty and cannot be known until the resources have been developed and in some cases depleted. Decisions made under uncertainty, usually unavoidable, are the norm for many resource-related issues. The format and method of estimation of undiscovered conventional oil and gas resources discussed in this report are designed specifically to facilitate the best possible decisions.

The Department of Energy, Mines and Resources, recognizing the need for independent authoritative estimates of Canada's resources, began an inventory of our undiscovered conventional oil and gas in 1971. The first estimates were published in 1973 in *An Energy Policy for Canada — Phase I.* Methods for making estimates of undiscovered resources and the capability to process information have evolved considerably during preparation of periodic internal estimates. The 1975 estimates presented in this report will serve as a guide to energy policy. They are, however, not the final numbers and will continue to evolve as more information becomes available. The estimates in this report are not constrained by economic considerations other than the stipulation that the oil and natural gas is technically recoverable from the reservoir.

The next step in the resource-evaluation process is the preparation of an economic assessment of Canada's oil and natural gas resources; answering the

basic question — how much oil and gas will become available and at what price? This is a complex question involving detailed estimates of the geographical location and physical characteristics of as yet undiscovered resource accumulations as well as detailed studies of the costs of drilling wells and constructing facilities in each of Canada's sedimentary source basins. The Department of Energy, Mines and Resources anticipates the publication of such a study in 1977.

The oil sands deposits of Alberta constitute an enormous source of hydrocarbons which when converted to synthetic crude can be used as a feedstock to produce refined petroleum products. The magnitude of these resources is known with a reasonable degree of accuracy, far better in fact than our knowledge of as yet undiscovered conventional oil and gas. Considerable additional effort however must be expended to define the physical and economic characteristics of the deposits and to establish what portion of this resource may eventually contribute to our energy supply. The Department of Energy, Mines and Resources has not carried out the comprehensive geological investigations necessary for the preparation of a complete inventory of the reserves and resources of the oil sands.

The estimates for the oil sands deposits presented in this document were prepared by the Energy Resources Conservation Board of the Province of Alberta and the relevant section of the report was written by the Alberta Board. The Department of Energy, Mines and Resources gratefully acknowledges this contribution.

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SUMMARY

Part I. Conventional Oil and Natural Gas*

A geological appraisal of Canada's potential oil and gas resources has recently been completed by the Department of Energy, Mines and Resources, summary results of which are presented in Table 1 and Figure 1. Single unique values for Canada's oil and gas potential are not presented; the appraisal provides estimates of *the range of probable occurrence of oil and gas resources* within each sedimentary (hydrocarbon-bearing) basin. (The term *resource,* as employed throughout this report, includes remaining recoverable reserves and potential or undiscovered oil and gas.)

An economic assessment of these resources will be published by the Department early in 1977. It will provide estimates of the costs at which these energy resources, our possible future oil and gas supplies, might become available.

As of year end 1975, about 85 trillion cubic feet (Tcf) of gas had been discovered in Western Canada of which 26 Tcf had been produced leaving 59 Tcf remaining reserves. At the 100% probability level Figure 1 also includes up to 25 Tcf of discovered natural gas in Canada's frontier regions.

Similarly, at year end 1975 about 16.4 billion barrels of recoverable crude oil and natural gas liquids had been discovered in Western Canada of which 8.4 billion barrels had been produced, leaving 8.0 billion barrels remaining reserves. At the 100% probability level only a few hundred million barrels of crude oil and natural gas liquids are known to exist in the frontier regions; a figure of 8.5 billion barrels is shown in Figure 1 at the 100% probability level as the remaining liquid hydrocarbon resource for all of Canada.

In addition to these known resources there is a "high" (90%) probability that about 16 billion barrels of combined crude oil and natural gas liquids remain to be discovered and a "low" (10%) probability that about 34 billion barrels may be discovered; about four fifths of which will be found in frontier areas. For natural gas, between 145 and 294 Tcf remain to be discovered at the "high" and "low" probability levels respectively, about nine tenths of which will be found in frontier areas.

Using an approximate thermal equivalent of 6 000 cubic feet of natural gas per barrel of oil, the estimates in Table 1 indicate that Canada's remaining oil and gas potential is expected to be dominantly gas. The table further indicates that the likelihood of frontier crude oil resources exceeding those of Western Canada, even totalling all basins, is low. The prospects for natural gas are considerably better; however the probability of a single basin approaching the potential of Western Canada, although real, is less than 10 per cent.

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*These estimates exclude the large oil sands resources of Alberta, which are dealt with separately.

It must be emphasized that the estimated values of oil and gas potential, described in terms of probability, must not be regarded as reserves. Most emphatically, the estimates should not be regarded as assured supplies. At the time of estimation for the frontier regions, only a small portion of the resources were in the discovered category. Further, depending upon the location, climate and environmental constraints existing in each area, the discovered resources may fall short of the threshold volume required to justify the construction of the

Table 1

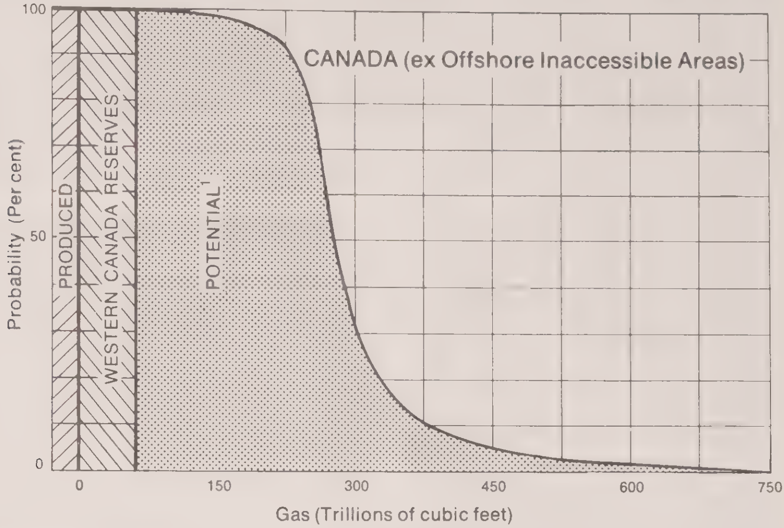
SUMMARY OF OIL AND NATURAL GAS RESOURCES OF CANADA — 1975*
(Remaining Reserves, Discovered Resources and Undiscovered Potential)

	Likelihood of Existence		
	"High" 90% Probability	*50/50 Chance 50% Probability*	*"Low" 10% Probability*
		Oil Resources (billions of barrels)	
REGION			
Atlantic Shelf South	1.2	1.9	3.0
Labrador-East Newfoundland Shelf	1.7	2.6	4.5
Northern Stable Platform Basins	0.01	0.6	3.2
St. Lawrence Lowlands	0.04	0.09	0.2
Western Canada	10.9	11.7	13.5
Mainland Territories	0.3	0.5	1.0
Mackenzie Delta-Beaufort Sea	4.3	6.9	12
Sverdrup Basin	1.1	2.0	4.0
Arctic Fold Belts	0.5	1.8	4.3
Total Canada (Accessible Regions)	25	30	43
		Gas Resources (trillions of cubic feet)	
REGION			
Atlantic Shelf South	8.6	13.2	20
Labrador-East Newfoundland Shelf	18	26.7	45
Northern Stable Platform Basins	0.4	2.3	12
St. Lawrence Lowlands	0.7	1.4	3.2
Western Canada	89	97	107
Mainland Territories	6.0	9.7	20
Mackenzie Delta-Beaufort Sea	39	60	99
Sverdrup Basin	21	40	80
Arctic Fold Belts	2.9	11	26
Total Canada (Accessible Regions)	229	277	378

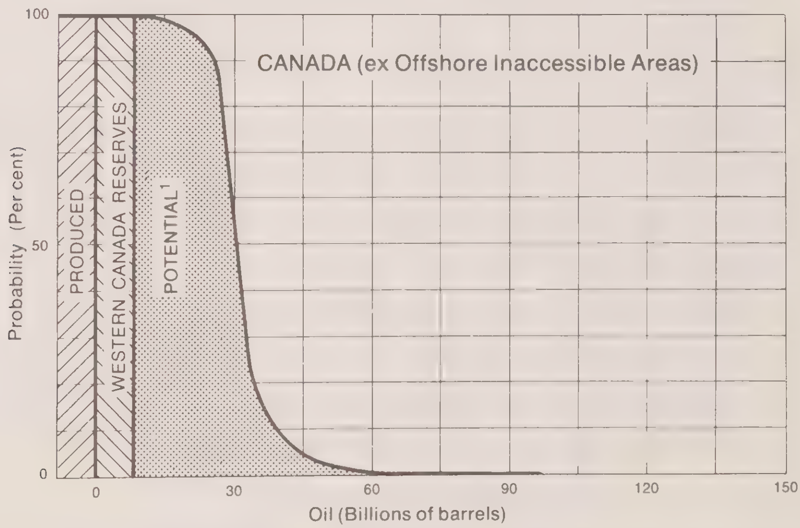
NOTE: These columns do not total arithmetically to the Canada totals because individual curves must be summed using a statistical technique described elsewhere in the report.

*Prepared by Geological Survey of Canada.

Figure 1. **Estimates of oil and natural gas resources excluding inaccessible offshore areas (cumulative per cent probability distribution). *Probability in per cent; **Resource in billions of barrels of oil and trillion cubic feet of gas.**



Probability*	100	90	80	70	60	50	40	30	20	10	5	0
Resource**	84[2]	229	243	255	266	277	289	305	328	378	433	750



Probability*	100	90	80	70	60	50	40	30	20	10	5	0
Resource**	8.5[2]	25	26	27	29	30	31	33	36	43	51	97

[1]Includes discovered resources in frontier regions.
[2]Includes Western Canada reserves plus discovered resources in frontier regions. Past production is not included.

required transportation systems. Finally, pool size, well productivities and other factors affecting development costs may be such as to preclude the economic development of many of the fields at reasonable price levels.

Highlights of the oil and gas estimates of this report are:

1. The bulk of the hydrocarbon potential (mainly gas) lies in the three frontier regions, the Mackenzie Delta-Beaufort Sea, Arctic Islands and Labrador Shelf regions which are expensive and difficult to explore. Additions to the short-term supply will have to come largely from the Western Canada Sedimentary Basin.
2. For the frontier regions, the bulk of the potential is likely to occur in offshore areas with very hostile environments and attendant high costs, logistical problems, and environmental risks. This potential is considered unlikely to add materially to the short- and medium-term supply.
3. Significant undiscovered resources remain in the Western Canada Sedimentary Basin. These will occur mostly in the deeper part of the basin, and in low productivity gas sands, and in heavy oils in the shallower part of the basin.
4. The Mackenzie Delta-Beaufort Sea area is an above-average prospective petroleum region. The largest part of the potential in this area is probably in the offshore region. Significant volumes of gas have already been established in the Mackenzie Delta and there are indications that there may also be large quantities of liquid hydrocarbons.
5. A large potential for gas exists in the Sverdrup Basin and in the Arctic Fold Belts of the Arctic Islands. The largest part of this potential is also in the offshore region.
6. The major portion of petroleum potential on the eastern seaboard lies beneath the Labrador Shelf.

Estimates of both oil and gas resources for Canada have decreased substantially from the last Departmental estimates published in 1973. One of the major reasons for the reduction is that the current estimates exclude areas considered to be inaccessible using known technology whereas the 1973 estimates included areas such as the continental slopes and rises and the Arctic Coastal Plain offshore. This exclusion is responsible for approximately one third of the reduction from the previous estimates. Significantly however, the decrease also results from the new and predominantly disappointing flow of information that has been generated by exploration in the interim period. Certain of the changes in estimates have resulted from an increased capability to process information and improvements in methodology.

Part II. Oil Sands Deposits of Alberta*

The oil sands of Alberta represent the largest localized accumulation of petroleum in the world. However a large part of this resource is not recoverable

*The resources considered in this section include the bituminous sands deposits at Athabasca, Peace River, Wabasca and Buffalo Head Hills and the heavy oil deposits at Cold Lake, all in Alberta.

using known technology and of the part that is recoverable, only a fraction is likely to become available under current and projected economic conditions. If it is assumed that mining techniques may be only marginally economic then only those deposits lying beneath 50 feet or less of overburden might be considered as economically recoverable reserves. This amounts to about 7 billion stocktank barrels of synthetic crude of which the existing Great Canadian Oil Sands and the Syncrude project under construction are expected to yield between 1.5 and 2 billion barrels during a projected 25-year period of production.

In 1974 the Alberta Energy Resources Conservation Board estimated potential ultimate recoverable resources for the whole region of some 250 billion barrels of synthetic crude on the basis of potential recovery techniques and deposit characteristics. At present, only a small portion of outcropping and shallow deposits are being exploited on a commercial scale, and the remaining estimated resources of crude bitumen from this source are considered by the Alberta Board to comprise about 27 billion barrels of synthetic crude. The remainder (about 223 billion barrels) must be recovered by *in situ* techniques, and although extensive tests have been conducted, no full-scale commercial production by this method has yet been realized from any of the Alberta deposits.

Part I
CONVENTIONAL OIL AND NATURAL GAS RESOURCES OF CANADA

INTRODUCTION

In the year 1975 some 65% of Canada's primary energy was provided by oil and gas. By the year 1990 this percentage is expected to decrease marginally to 60% of our primary energy consumption. While it may be hoped that production of synthetic crude oil from the oil sands may furnish an increasing proportion of this requirement, present projections indicate that oil sands production may supply no more than 20% of our liquid hydrocarbon needs by the year 1990. These figures indicate our strong and continuing dependence upon conventional oil and gas to supply our energy demands.

A major requirement for a comprehensive Canadian energy policy is the recognition of this continuing dependence upon conventional oil and gas which, in turn, leads to the recognition of the need to determine as accurately and as soon as possible the extent and distribution of oil and gas resources in Canada. This "need to know" may be expressed in the form of the following questions.

1. *How much oil and gas is likely to exist in Canada?*

2. *What is the geographic distribution of these oil and gas resources among frontier basins and the established producing areas?*

3. *What degree of confidence can be attached to these estimates?*

4. *What are the likely rates of discovery and development of production capability from these resources?*

5. *What is likely to be the cost of these resources delivered to the Canadian market place?*

This report deals directly with the first three of these questions and provides a starting point for further analysis to provide forecasts of the trend of discoveries and the cost of delivery to the market place.

In attempting to quantify Canada's potential conventional oil and gas resources EMR depends on the construction of cumulative probability curves (see Appendix 1) for oil and gas occurrences for various basins, regions or other identifiable features. The curves are drawn with the knowledge of actual occurrences and incorporating geological judgment.

The first phase of the process is the identification of the *exploration plays* present in a given area. A *play* consists of a group of prospects and/or discovered fields having common geological characteristics such as source rock, trapping mechanism, etc. Because each factor may vary widely in favourability for hydrocarbon accumulation, their combination in a *play* provides the possibility for a wide range of values. A *play* may contain both oil and gas together or separately.

The hydrocarbon potential of individual exploration plays within a sedimentary basin is summed using a statistical technique (the *Monte Carlo method*) as described in Appendix 1. Estimates prepared in this manner by the Geological

Survey of Canada, for nine separate geological-geographical regions of Canada are presented in the following pages. Comparisons are drawn with previous EMR estimates and with those available from several outside sources. A description of regional geology and exploration activity is included with each regional description. Estimates for basins are also added using the Monte Carlo method to obtain the total resource estimates for Canada.

Terminology

The word *resource* as used here includes all conventional oil and gas accumulations known or inferred to exist. Reserves comprise that portion of the resource that has been discovered.* The word *potential* describes that portion of the resource inferred to exist but not yet discovered. The terms *potential* and *undiscovered resources* are thus synonymous and can be used interchangeably.

The terms *reserves* and *resources* are used differently for oil and gas than for various other commodities, a difference that reflects the general practice within respective industries. Within the mineral industries the term *reserves* implies current economic viability whereas in the petroleum industry use of the term *reserve* is not as restricted.

Major factors determining the portion of a resource that becomes part of the supply create a hierarchy of terminology. Knowledge of existence is indicated by use of the terms *reserve** (for discovered resources) and *potential* (for inferred resources). The modifiers *recoverable, non-recoverable, economic* and *non-economic* describe the impact of technology and economics.

Within this report gas values given are for marketable or pipeline gas; oil values are for stocktank barrels. Where natural gas liquids (NGL) have been estimated, they are included in the oil values. For convenience the unmodified terms *reserve* and *potential* should be read as equivalent to recoverable reserve and recoverable potential.

Definitions for other technical terms are given in Appendix 2, a Glossary of Terms.

Data Base

The Department of Energy, Mines and Resources has been developing an oil and gas inventory program since 1971. As data and methodology have evolved the Geological Survey of Canada has prepared successive estimates of Canada's oil and gas resources. The estimates contained in this report are based mainly on data available to the end of 1974 although some information resulting from 1975 exploration programs has been incorporated.

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*Discovered resources in frontier regions form a special case and are not included in reserves category but are added to potential. For further details see section "Estimates of Reserves of Oil and Natural Gas".

The estimation of the potential of any region depends upon data supplied by industry and government scientists and involves both subjective and objective approaches. Most of the types of data normally used by industry in analyzing exploration plays were available for the preparation of the oil and gas estimates presented here. Data are evaluated in the light of new concepts and hypotheses and in the light of oil and gas occurrences throughout the world.

A resource analysis depends to a considerable degree on the accumulated knowledge concerning the overall framework of the earth's crust, in particular the various sedimentary basins throughout Canada. Such data include the interrelationships of rocks in various areas and their geometric configuration. In assessing the potential of an area, the first step is to identify major regions or sedimentary basins of different character. Specialized data are then identified for each region. For example data derived by specialists in geochemistry from the study of the organic material contained in sedimentary rocks provide particularly useful information on the extent and quality of the source rocks within which hydrocarbons may be generated. Such data are fundamental to building an understanding of gas and oil occurrences in a region. Geophysical data such as reflection seismic sections provide a better understanding of the shape, size and character of known and potential oil and gas accumulations. Information on past exploration activity and statistics on any hydrocarbon production is of course also used in making estimates.

Methodology

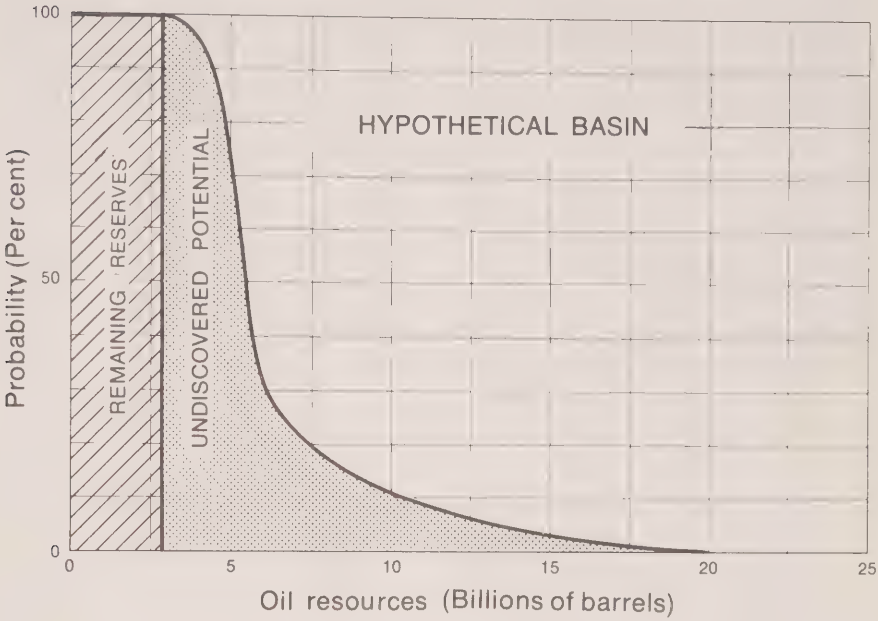
The estimates given in this report are in the form of cumulative per cent probability (relative frequency) distributions. The complex technique employed is not easily summarized. For the benefit of those involved in resource estimation and for those who may be concerned with understanding how the estimates that follow were derived, the procedure is described in some detail in Appendix 1.

The distributions are presented in the form of curves, each of which shows the relationship between the magnitude of the estimate and the level of probability assigned to that estimate. The curves express the cumulative probability that resources "greater than" the corresponding graphed value could exist. Thus Figure 2, representing a hypothetical basin, should be read as showing that there is a 30% probability* that the resource is greater than 6 billion barrels and a zero probability that it exceeds 20 billion barrels. These curves include both reserves and potential (undiscovered) resources. In the example the estimator expresses the opinion that the actual size of the resource lies between 3 and 20 billion barrels. The tail of the curve (between 15% and 0%) expresses the opinion that there is a low but finite probability that much larger resources than shown for the higher probabilities may occur. Giant accumulations could result from the

*Probability refers to per cent probability throughout this report.

simultaneous occurrence of such factors as excellent source rocks, thick porous reservoirs and large traps with favourable timing of migration. This simultaneous occurrence is a very unlikely or low probability event.

Figure 2. Estimate of oil resources for a hypothetical basin (cumulative per cent probability distribution). For this basin there is a 30% probability that the resource is greater than 6 billion barrels and a zero probability that it exceeds 20 billion barrels.



The curves that follow for various regions of Canada reflect an infinite number of estimates *but only one real value exists,* a value that will not be known until the resource is depleted. However, with an increasing level of information derived from geological mapping and related studies, geophysical data, drillhole results and the attainment of success or failure in exploration programs, the range of the estimates will be reduced. New reserves will move the 100% probability value to the right in Figure 2. Negative drilling results, such as finding a prospect to be barren, may reduce the maximum value of this estimate.

It must be emphasized that these estimated values of potential resources, described in terms of probability, are not to be regarded as reserves. Most emphatically, the estimates should not be regarded as assured supplies. First, only a portion (about 3 billion barrels in this hypothetical case) of the total resource had been discovered as of the time of estimation. Also, pool sizes, well productivities and other factors affecting development costs may be such as to preclude the economic development of many of the fields at reasonable price levels. The resource estimates nonetheless form the foundation for the estimation of possible future economic reserves of oil and gas and the rate at which future supplies may be obtained. Such an analysis is currently underway.

In the near future the Department of Energy, Mines and Resources expects to publish an economic assessment of future oil and gas supplies based on the principles outlined above and making use of the resource estimates presented herein as a data base.

Although estimates of future supply are the final objective, the curves of estimates of resources presented in this report provide much useful information. For example the shape and range of the curves reflect the current level of information for a region. Also the curves allow selection of probability levels appropriate to the type of decision under consideration. For example, when deciding on Canada's export commitments, one would tend to select the higher probability ranges, whereas if policy concerning exploration were being considered, lower levels, with their larger possible returns would be considered.

ESTIMATES OF RESERVES OF OIL AND NATURAL GAS

The most recent reserves estimates prepared by the National Energy Board indicate reserves of 6.878 billion barrels of remaining conventional crude oil and 59.8 Tcf (1 000 Btu basis) of remaining marketable gas as of year-end 1974. These estimates are defined by the Board as being "established reserves" and consist of the proved reserves plus some portion of probable reserves for each oil or gas pool. These figures include only reserves in the established producing areas, mainly in Western Canada. They exclude both frontier reserves and the oil sands.

Historically the National Energy Board has not published estimates of reserves of natural gas liquids (NGL)*. Estimates of natural gas liquids adapted from the Canadian Petroleum Association (CPA) are used in this report in order to present a comprehensive picture of Canada's conventional oil and gas resource base. Similarly, updating the NEB estimates of established reserve of crude oil and natural gas to January 1, 1976 has been accomplished using CPA estimates of net reserves changes during 1975. The resulting figures are as follows:

Table 2

RESERVES ESTIMATES OF CONVENTIONAL OIL AND NATURAL GAS[1]
(NON-FRONTIER AREAS AS OF JANUARY 1, 1976)
(Billions of Barrels and Trillions of Cubic Feet)

	Original Recoverable	*Cumulative Production*	*Remaining Recoverable*
Crude oil[2]	13.8	7.4	6.4
Natural gas liquids[3]	2.6	1.0	1.6
Total liquid hydrocarbons	16.4	8.4	8.0
Natural Gas (marketable)[4]	85	26	59

[1]These estimates *exclude* both the frontier areas and oil sands reserves.

[2]Based on NEB January 1, 1975 estimate of "established reserves" of 6.878 billion barrels remaining, and updated using CPA estimates.

[3]CPA estimates.

[4]Based on NEB January 1, 1975 estimate of remaining "established reserves" of 59.8 Tcf @ 1 000 Btu per cubic foot, and updated using CPA estimates, expressed in terms of Tcf @ 14.73 psia and average heating value.

Essentially there has been very little change in remaining marketable gas reserves since 1971 — additions have been roughly equal to production. As natural gas liquids are primarily extracted from natural gas, the same trend is

*As this commodity is produced in association with natural gas, Board regulation of interprovincial and export trade in NGL's has been effected through forecasts of supply based on producibility.

evident for NGL's. For crude oil, however, a downward trend has been evident since about 1970. New discoveries have been less than annual production since 1970 and exploration in the established areas has been unrewarding in terms of new oil finds. Current remaining reserves of conventional crude are down some 17 per cent from the peak year of 1970.

In frontier areas, hydrocarbons have been discovered but an exact quantification of these reserves would be premature and, indeed, in most cases, impossible because many discoveries are as yet based on a single well or are only partially delineated. While estimates of reserves could be made on the basis of seismic and geological interpretations, the degree of confidence in these estimates varies considerably. It is possible, nonetheless, to specify the magnitude of these volumes in terms of ranges. To date, exploration activities in Canada's frontier areas have resulted in the discovery of about 0.5 billion barrels of crude oil and natural gas liquids and about 25 trillion cubic feet of natural gas. Development of threshold volumes, government approvals of transportation systems, supply economics, the concerns of native peoples and environmental constraints will all have an impact on whether these discovered resources will eventually contribute to Canada's energy supplies.

Further details on discovered resources established in frontier areas are included in the discussions and curves of estimates for individual regions in the next section of the report.

ESTIMATES OF OIL AND NATURAL GAS RESOURCES BY REGIONS

The geological-geographical regions into which Canada has been divided for oil and natural gas estimation are shown on Figure 3. This section of the report presents an estimate of the oil and gas resources for nine regions accompanied by a brief description of the general geology, the nature of hydrocarbon occurrences (if any) and the results of past and present exploration activity. A geological time scale is presented in Figure 4.

Because of the small scale of the diagrams depicting the resource estimates, exact figures cannot be read from the curves. To provide a set of selected figures, each of the curves is accompanied by a table showing the estimated volume of oil or gas (resource) and the probability of its occurrence (100%, 90%, etc. to zero).

It cannot be emphasized too strongly that it is incorrect to produce a total for a number of regions simply by adding up the various quantities (at corresponding probability levels) for individual regions. To arrive at totals, the addition was done with a statistical method called the "Monte Carlo" technique (see Appendix 1).

To facilitate comparisons of oil and gas on a thermal (Btu) basis, the curves have been plotted on approximately equivalent thermal scales.

Atlantic Shelf South (Figure 5)

Location. This region includes the continental shelf portion of the eastern seaboard from the International Boundary to southeast of Newfoundland including the Bay of Fundy, the southern part of the Gulf of St. Lawrence, plus portions of the offshore Maritime Provinces, a total area of 167 000 square miles (Region 1 in Figure 3). For the purpose of hydrocarbon-resource estimation this region has been divided into four areas — Scotian Shelf, Grand Banks Shelf, Magdalen basin and Sydney basin.

Geology. The Magdalen and Sydney basins comprise most of the Gulf of St. Lawrence, the Cabot Strait and adjacent parts of the Maritime Provinces. They are similar in that they are filled mainly with sandstones, siltstones and shales, with some coaly beds — an assemblage deposited in a nonmarine environment generally unfavourable for the generation of hydrocarbons. In the Magdalen basin, the lower part of the section includes carbonate rocks, salt and anhydrite. This sequence of sedimentary rocks was deposited largely during the Carboniferous Period and ranges in age from about 225 to 350 million years. Because of the predominantly nonmarine nature of the rocks and the coaly material included with them, the main hydrocarbon expected is dry gas.

The best hydrocarbon-trapping opportunities in the Magdalen basin are related to the salt which has flowed plastically into salt domes and salt pillows

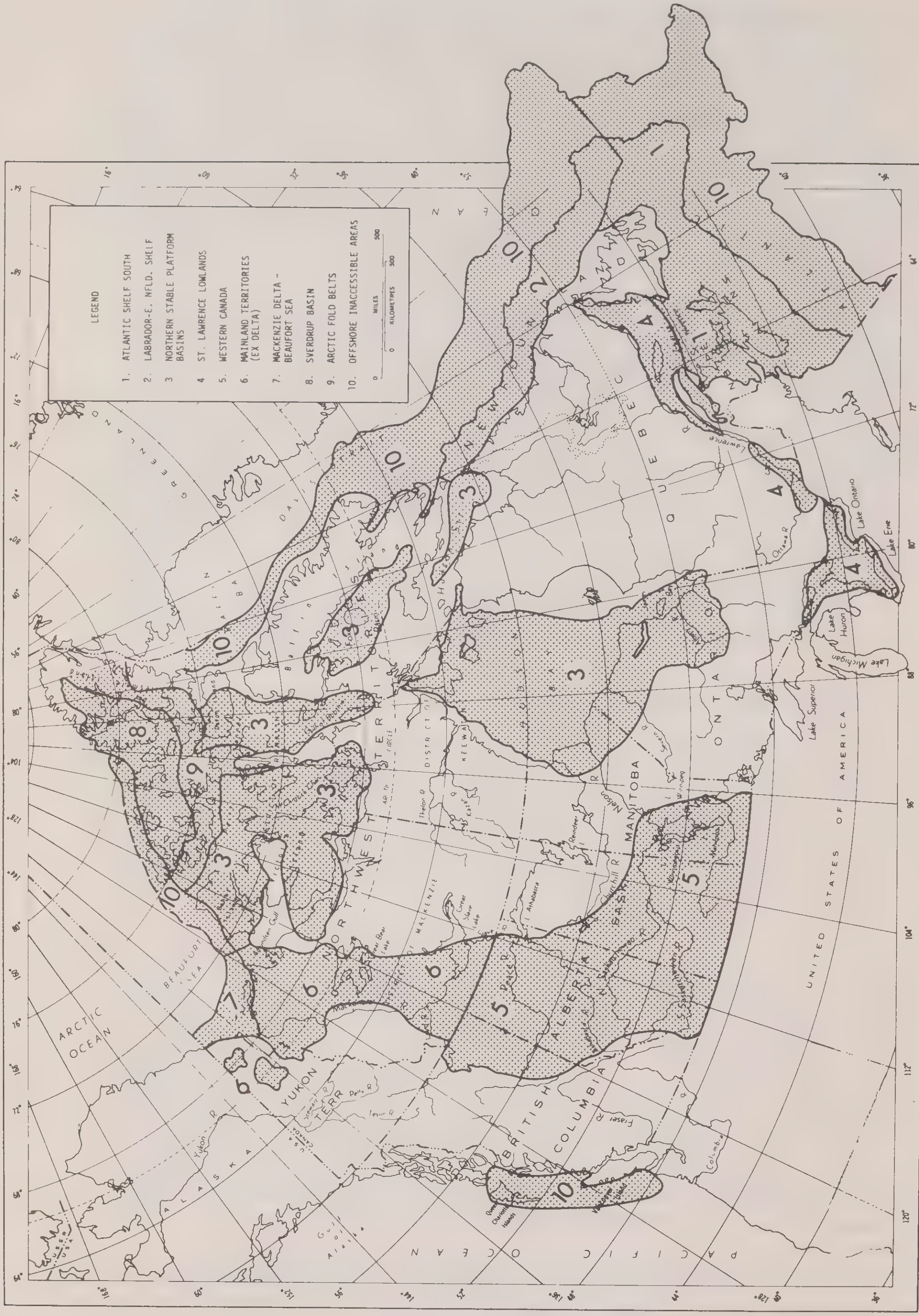


Figure 3. Map of regions for which estimates are provided.

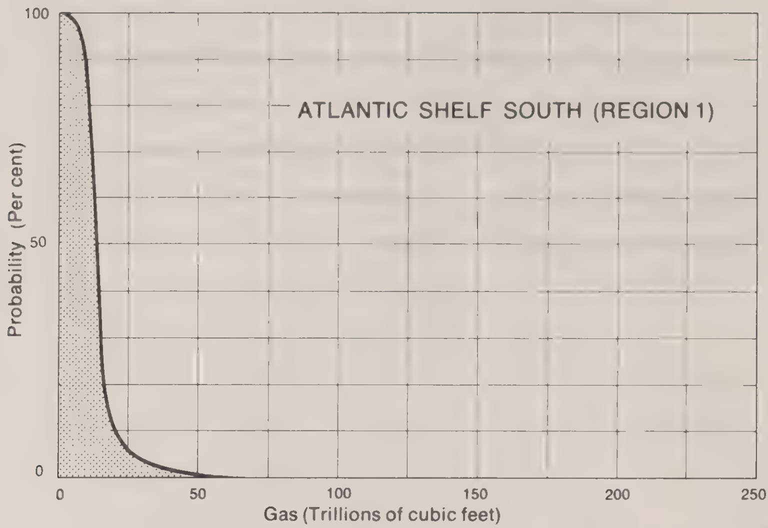
Figure 4. Geological time scale.

Era		Period	Total estimated time in years from present
Cenozoic		Recent Pleistocene	1,500,000
	Tertiary	Pliocene Miocene Oligocene Eocene Paleocene	65,000,000
Mesozoic		Cretaceous Jurassic Triassic	225,000,000
Paleozoic		Permian Carboniferous	
		Devonian Silurian	
		Ordovician Cambrian	570,000,000
Precambrian			>3,000,000,000

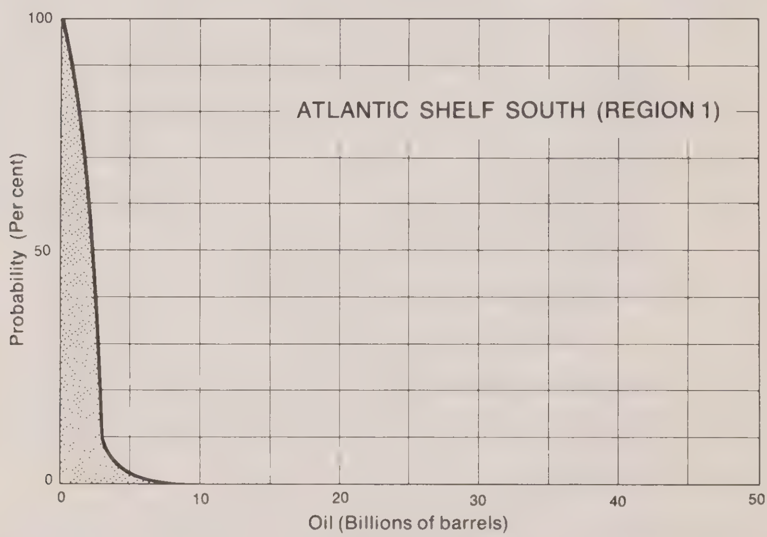
with the resulting uplift of portions of the overlying porous sandstones forming potential traps. Other types of traps may have been formed by basement fault blocks and the up-dip pinchout of porosity into non-porous rocks in both the Magdalen and Sydney basins.

The Scotian Shelf, the area of the continental shelf southeast of Nova Scotia, is underlain by a seaward-thickening wedge of Mesozoic and Cenozoic rocks which attains a thickness of more than 30 000 feet beneath the outer edge of the continental shelf south of Sable Island. The basal portion of this sedimentary sequence consists of red beds and salt and has little oil and natural gas potential.

Figure 5. Estimates of oil and gas resources of the Atlantic Shelf South region (cumulative per cent probability distribution). *Probability in per cent; **Resource in billions of barrels of oil and trillion cubic feet of gas.



Probability*	100	90	80	70	60	50	40	30	20	10	5	0
Resource**	1.0	8.6	10	11	12	13	14	16	17	20	23	52



Probability*	100	90	80	70	60	50	40	30	20	10	5	0
Resource**	.09	1.2	1.4	1.6	1.8	1.9	2.1	2.3	2.5	3.0	3.4	7.8

Overlying the salt is a succession of carbonates and shales which may contain hydrocarbon accumulations in either structural or stratigraphic traps. These beds are in turn overlain by a thick sequence of deltaic sands and shales which have yielded numerous hydrocarbon shows in the wells drilled to date.

A variety of structure types provide trapping opportunities beneath the Scotian Shelf. These include salt domes and pillows and basement fault blocks which arch the overlying porous rocks, growth faults which reverse the dip on porous sand beds to form closure, and numerous pinchouts of sand beds.

Beneath the Grand Banks of Newfoundland the lower carbonate beds have been highly deformed by the underlying salt but many of the resulting structures were subsequently breached by a lengthy period of erosion and any hydrocarbons they may have contained have been lost. The overlying sandstone and shale sequence is much thinner than that on the Scotia Shelf and, with poorer source rocks, has less oil or gas potential.

Exploration Activity. Almost 100 wells have been drilled in the offshore portions of Region 1. All but five of these have been drilled on the Scotian and Grand Banks shelves. By end of 1975, six small pools of oil and gas had been discovered near Sable Island and several less important shows had been reported. The discoveries in the combined fields in the Sable Island area comprise a little over 1 trillion cubic feet of gas and somewhat less than 100 million barrels of oil.

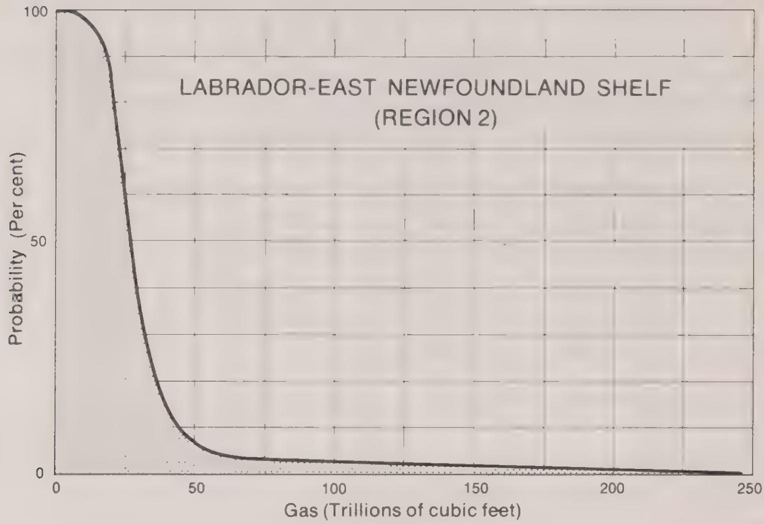
Discussion. Only modest discoveries have been made in the Atlantic Shelf South region. There are many possible plays in the region, most of which have been tested in a number of places with generally disappointing results. The nature of the Cretaceous sequence on the Scotian Shelf indicates that a number of small- to medium-sized pools may occur. Drilling to date has indicated that fields will most likely consist of a series of relatively thin stacked reservoirs.

The estimate curves, Figure 5, indicate approximately equal amounts of potential for oil and gas. In view of the exploration results and comments on the geology of the areas, the estimates shown by these curves may appear rather optimistic, but it should be noted that they represent the estimates for a very large volume of sedimentary rocks which appear to be relatively lean. Although industry has reduced its exploration activity to a low level, some programs are continuing. In the Magdalen and Sydney basins, because of their proximity to land, and the large markets of Eastern Canada, many of the relatively small-sized accumulations expected in these two basins may prove to be economic.

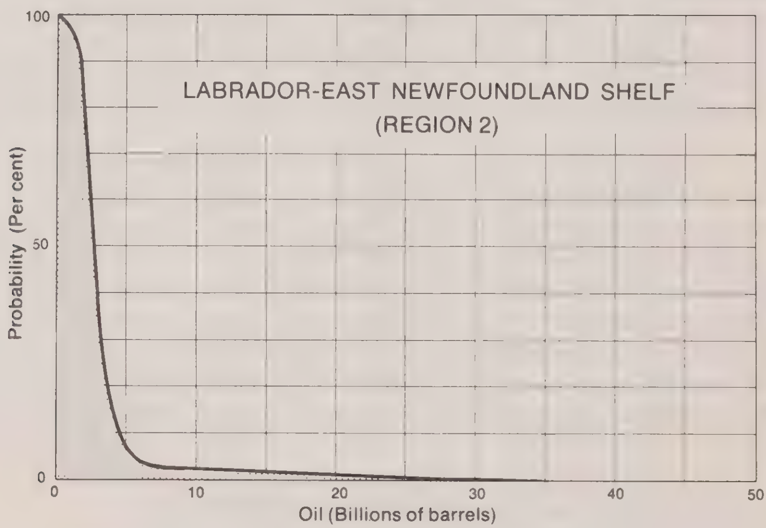
Labrador-East Newfoundland Shelf (Figure 6)

Location. This region (Region 2 in Figure 3) extends from the northeast Newfoundland Shelf along the Labrador Shelf to Hudson Strait, a distance of 1 000 miles. In this area the continental shelf extends to water depths of up to 1 500 feet.

Figure 6. Estimates of oil and gas resources of the Labrador-East Newfoundland Shelf region (cumulative per cent probability distribution). *Probability in per cent; **Resource in billions of barrels of oil and trillion cubic feet of gas.



Probability*	100	90	80	70	60	50	40	30	20	10	5	0
Resource**		18	20	23	25	27	29	32	36	45	55	242



Probability*	100	90	80	70	60	50	40	30	20	10	5	0
Resource**	0	1.7	2.0	2.2	2.4	2.6	2.9	3.2	3.6	4.5	5.7	34

Geology. The thick wedge of sedimentary rocks lying beneath the continental shelf along this stretch of the coastal margin is younger than that of the previously discussed southern Atlantic Shelf. East of Newfoundland, post-Paleozoic deposition commenced early in the Jurassic Period, about 200 million years ago, while off Labrador sedimentation may not have commenced until the Cretaceous, about 130 million years ago. The predominant rock types are sandstones and shales that overlie a basement which is broken into large, elongate fault blocks. The trapping configurations in this area are largely related to these fault blocks with sandy reservoir beds draped over and wedged up against them. In addition there are salt structures east of Newfoundland, numerous possibilities for pinchout of sandstone beds, and a possibility of porosity occurring in remnants of older Paleozoic beds capped by Cretaceous shales. The discoveries to date indicate that good source and reservoir rocks exist in the Labrador portion of this region.

Exploration Activity. Significant exploration drilling activity in this area commenced in 1973. In that year, two wildcat wells were drilled, one of which, Bjarni H-81, turned out to be a significant gas discovery. This was followed in 1974 with a discovery at the Gudrid well. In 1975 an additional five wells were put down during the short drilling season and hydrocarbons, unconfirmed by testing, were reported from two holes. One of these, Snorri, reportedly encountered a gas-bearing sandstone reservoir. None of the discovery wells has been followed by development drilling and thus no reliable estimates of reserves are available.

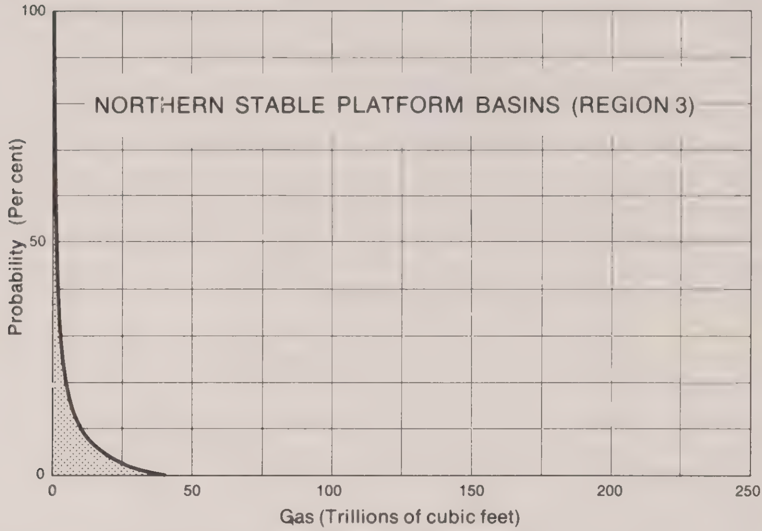
Discussion. The probability curves (Figure 6) for the Labrador-East Newfoundland Shelf region indicate significant potential for oil and gas. These curves are highly skewed, with the maximum values several times larger than the mean, indicating the possibility of large gas and oil resource potential at low probabilities. The discoveries lie in several hundred feet of water in an area where the bottom is scoured by icebergs, and techniques for production are not yet available. Further technological development will therefore have to precede production of hydrocarbons. The encouraging results encountered at the Bjarni, Gudrid and possibly the Snorri wells, make this region one of the prospective frontier oil and gas provinces of Canada.

Northern Stable Platform Basins (Figure 7)

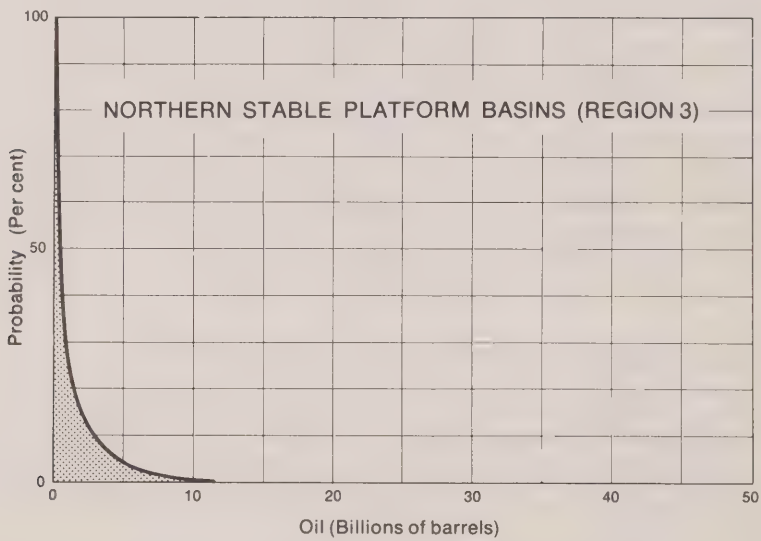
Location. This region (Region 3 in Figure 3) includes several very large areas grouped together because of similar geology. It includes all of the Paleozoic sedimentary rocks surrounding and under the Hudson Bay area as well as all of the flat-lying rocks of the southern Arctic Islands and adjacent areas on the northern mainland.

Geology. These areas, underlain by thin, flat-lying, widespread carbonate rocks, are very little deformed with some local exceptions, as in Hudson Bay. They comprise Paleozoic rocks ranging in age from 350 million to about 600 million

Figure 7. Estimates of oil and gas resources of the Northern Stable Platform basins region (cumulative per cent probability distribution). *Probability in per cent; **Resource in billions of barrels of oil and trillion cubic feet of gas.



Probability*	100	90	80	70	60	50	40	30	20	10	5	0
Resource**	0	.35	.75	1.2	1.7	2.3	3.1	4.5	6.7	12	19	42



Probability*	100	90	80	70	60	50	40	30	20	10	5	0
Resource**	0	.01	.17	.28	.40	.57	.77	1.1	1.6	3.2	4.3	12

years. The oil and gas possibilities of these regions are poor in that there is a scarcity of potential source rocks for hydrocarbons, a lack of structural traps of any significance, and a lack of adequate sealing rocks for the reservoirs. The types of traps that can be anticipated here will be largely stratigraphic, that is to say, pinchouts of porosity up regional dips into impermeable rocks and possibly very small reef buildups. Perhaps the most interesting possibilities would be in basal sandstones. These are widespread and under the right conditions could pinch out along some of the regional arches, forming large stratigraphic traps. These conditions have a low probability of occurrence.

Exploration Activity. Recent drilling, of a small number of wells scattered throughout the region has met with no apparent success.

Discussion. The Paleozoic shelf carbonates, which do not appear to be highly structured, can be expected to have a relatively low hydrocarbon potential and this is reflected in the curves. Pool sizes in this type of environment are expected to be very small and those located in the offshore regions would be of dubious economic value. Because of the relatively unattractive potential, there is little exploration activity in these areas.

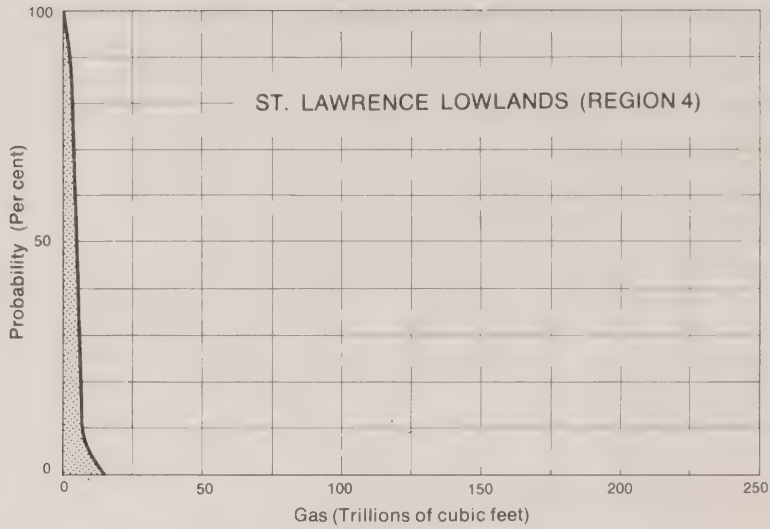
St. Lawrence Lowlands (Figure 8)

Location. This region (Region 4 in Figure 3) includes the Paleozoic rocks that extend in a narrow belt from the peninsula area of southwestern Ontario along the St. Lawrence River to, and including, Anticosti Island, adjacent offshore Gulf of St. Lawrence, and Gaspé Peninsula, a distance of some 1 500 miles.

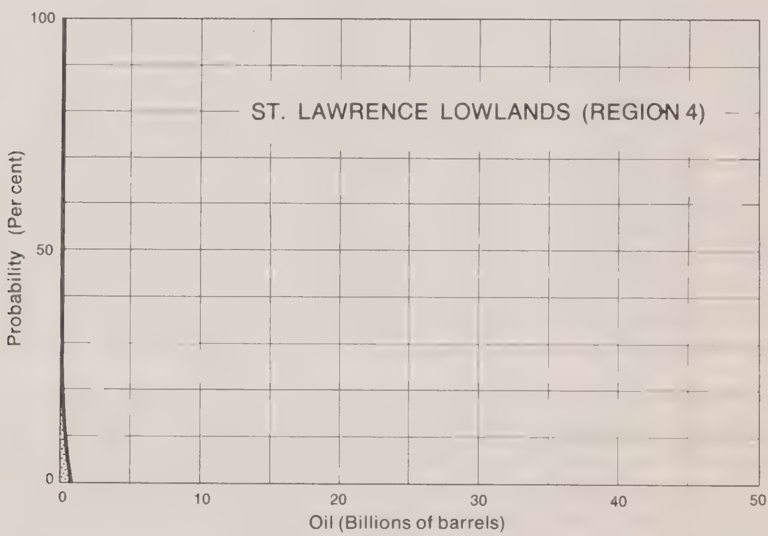
Geology. Like the Northern Stable Platform Basins, most of this region comprises a thin cover of Paleozoic carbonate rocks overlying the Precambrian Shield. The geological section of both regions is not unlike in that there is commonly a basal sandstone unit, locally with excellent porosity, overlain by carbonate rocks. Throughout this region there are various possible hydrocarbon-trapping configurations. In southern Ontario traps are formed by small reef buildups covered with salt, discontinuous porosity in carbonates draped over salt remnants, or in pinchouts and discontinuous basal sandstones. Within Gaspé Peninsula, strong structural deformation gives rise to large folds and thrust faults, and numerous small shows of hydrocarbons are related to these structures. Apparently deformation has been too intense and perhaps too late to catch the migrating hydrocarbons.

Exploration Activity. Initial exploration in the St. Lawrence Lowlands region began in southwestern Ontario in 1858, resulting in the discovery of the Oil Springs field in the same year. Since then over 100 000 shallow wells have been drilled resulting in the discovery of a multitude of small oil and gas fields. By the end of 1975 more than 53.4 million barrels of oil and 790 billion cubic feet of gas had been produced. Numerous wells have been drilled in the Quebec lowlands area with no significant success. The Gaspé region has had a long and sporadic exploration history but despite ubiquitous surface oil seeps, no commercial accumulations have been found.

Figure 8. Estimates of oil and gas resources of the St. Lawrence Lowlands region (cumulative per cent probability distribution). *Probability in per cent; **Resource in billions of barrels of oil and trillion cubic feet of gas.



Probability*	100	90	80	70	60	50	40	30	20	10	5	0
Resource**	.20	.71	.91	1.1	1.3	1.4	1.6	1.8	2.3	3.2	5.3	12



Probability*	100	90	80	70	60	50	40	30	20	10	5	0
Resource**	.01	.04	.06	.07	.08	.09	.10	.11	.14	.20	.33	.76

Discussion. The estimates of oil and gas resources (Figure 8) for this region are insignificant on a national scale. The curve for gas indicates some modest possibility for additional gas, a large part of which may be offshore in Lake Erie. Environmental considerations may inhibit development in this area. Despite the opinion that the potential is insignificant, exploration activity can be expected to continue because the very smallest pools will be economic in the onshore portions of this area. The relatively advanced state of exploration within the region is reflected in the steepness and short tails of the distributions. The only relatively unexplored part of the region lies in the northern Gulf of St. Lawrence south and east of Anticosti Island.

Western Canada (Figure 9)

Location. This region (Region 5 in Figure 3) includes sedimentary portions of the Prairie Provinces lying between the Precambrian Shield and the Rocky Mountains, south of 60° N latitude.

Geology. This is the best known area of Canada from the point of view of subsurface geology and is in a mature stage of exploration. The oil and gas region of Alberta lies in the southwestern part of the Western Canadian Sedimentary Basin, whereas southern Saskatchewan and Manitoba are on the northern side of the Williston Basin which extends across the International Boundary into Montana and North Dakota. Both basins are structurally simple and have low regional dips. Most of the oil and gas in both basins occurs in stratigraphic traps.

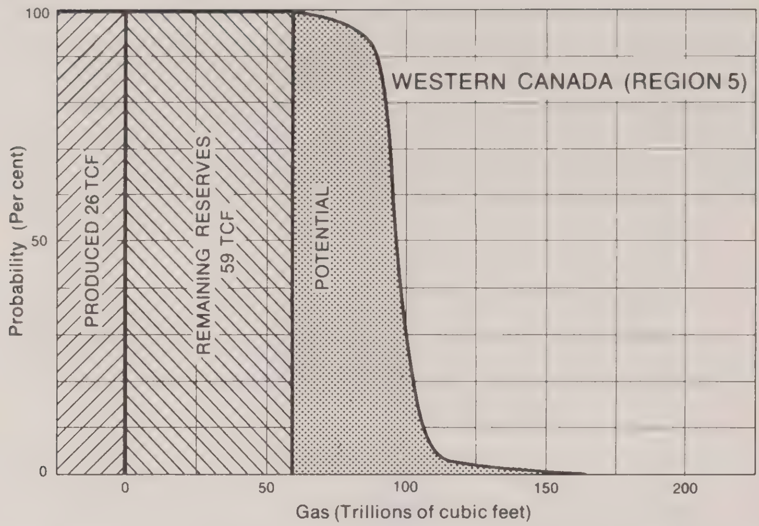
The Williston Basin in Saskatchewan and Manitoba is a simple, relatively shallow basin that characteristically has low hydrocarbon potential. The best prospects have been tested and the remaining potential seems to be small.

In Alberta there is reasonable expectation for additional hydrocarbon discoveries to be made in stratigraphic traps less obvious and smaller than those found to date, and in deeper parts of the basin that have not been thoroughly tested.

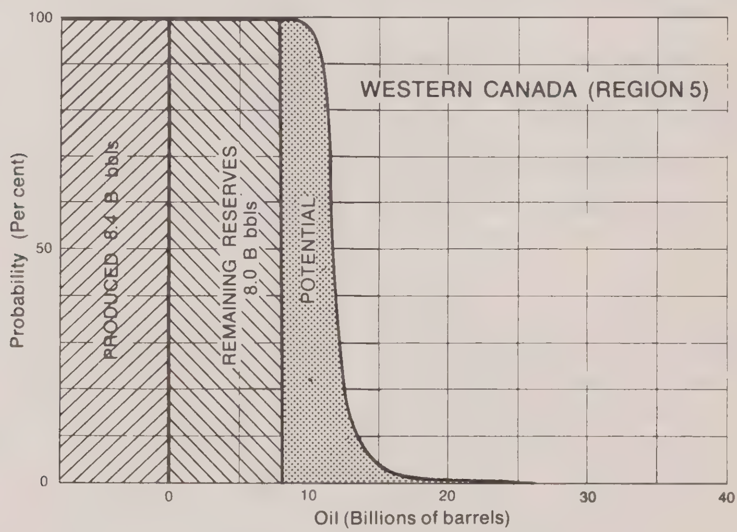
Northeastern British Columbia lies in the deeper part of the Western Canada Sedimentary Basin. Because the region was deeply buried in the past and in places has a relatively high geothermal gradient, the discoveries to date have been dominantly gas. It is anticipated that this trend will continue. Most of the drilling to date has been on surface structures or features such as reef edges — structures found easily by geophysical methods. As most of the obvious structures in the plains area have been tested, future exploration will be for relatively deep stratigraphic traps. A number of obvious structures remain to be tested in the disturbed belt of British Columbia, but to date exploration in this region has not been very encouraging.

Exploration Activity. The Western Canada Sedimentary Basin is now in a mature stage of exploration. More than 85 000 wells have been completed in the

Figure 9. Estimates of oil and gas resources of the Western Canada region (cumulative per cent probability distribution). *Probability in per cent; **Resource in billions of barrels of oil and trillion cubic feet of gas.



Probability*	100	90	80	70	60	50	40	30	20	10	5	0
Resource**	59	89	91	93	95	97	98	100	103	107	111	164



Probability*	100	90	80	70	60	50	40	30	20	10	5	0
Resource**	8.0	10.9	11.1	11.3	11.5	11.7	11.9	12.1	12.5	13.5	14.5	26.1

region since the discovery of the Leduc oil field in 1947 and these have resulted in finding more than 3 000 pools, most of which occur within Alberta. These contain remaining reserves of 59 trillion cubic feet of gas and 8.0 billion barrels of oil and natural gas liquids. The last major discovery in Alberta was realized in 1965, and from 1969 to the present the total remaining proven oil reserves have been declining.

Discussion. The estimates illustrated in Figure 9 are based largely on published data and were prepared in 1976. A major study, recently completed, examined the oil and gas resources on a play-by-play basis. Detailed analysis of this region was considered appropriate in view of its importance for short- and medium-term supply. The curves for Western Canada are different from those of other regions in that their shapes reflect the advanced stage of maturity of exploration.

Economic considerations in this area differ greatly from those in any of the frontier basins, as the infrastructure is already in place and logistical problems are minimal. Thus one might expect most pools, down to the smallest recognizable sizes, to be economic. It is likely that the larger pools, in most of the exploration plays, have already been found and exploration effort in the future will be devoted to searching for remaining smaller pools as well as improving the recovery from existing pools.

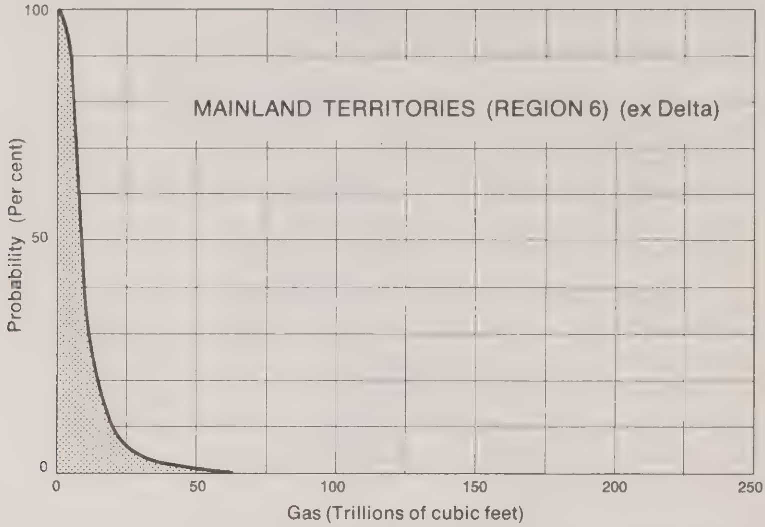
A significant proportion of the estimated potential falls into the category of heavy oils, in which perhaps there is room for considerable improvement in enhancement of recovery. Low-productivity gas sands found in southeastern Alberta will certainly add a large component to reserves but the major problem with this resource is its deliverability or the rate at which it will be produced and added to supply. Both of these problems are being examined in the studies now underway.

Mainland Territories (Figure 10)

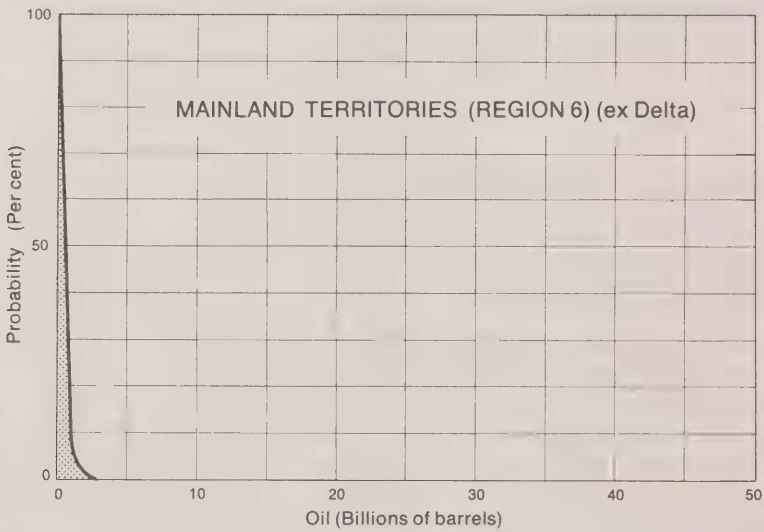
Location. This region (Region 6 in Figure 3) includes the continuation of the Western Canada Sedimentary Basin and extends north from the 60th parallel to the Mackenzie Delta, including intermontane basins such as Eagle Plains Basin.

Geology. The sedimentary basin fill thickens from zero on the Precambrian Shield to more than 10 000 feet in places near the mountain front. The rocks are dominantly Paleozoic carbonates with a basal sand overlying the Precambrian. There are some areas with overlying younger Cretaceous sands and shales in parts of the region. The possible hydrocarbon-trapping configurations include, as in the region to the south, stratigraphic pinchouts with porosity wedging updip into impermeable rocks. The basal sands may be involved in large regional structures as well as in more localized structures. Reef buildups, such as at Norman Wells, may occur. Large anticlines are known to occur in the Foothills of the mountains, such as at Pointed Mountain and Beaver River in the southern territories and in the intermontane basins.

Figure 10. Estimates of oil and gas resources of the Mainland Territories region (cumulative per cent probability distribution). *Probability in per cent; **Resource in billions of barrels of oil and trillion cubic feet of gas.



Probability*	100	90	80	70	60	50	40	30	20	10	5	0
Resource**	1.0	6.0	7.0	7.9	8.8	9.7	11	12	16	20	26	64



Probability*	100	90	80	70	60	50	40	30	20	10	5	0
Resource**	.05	.34	.39	.44	.49	.54	.61	.69	.81	1.0	1.3	3.1

Exploration Activity. Some 650 wells have been drilled in this area since the discovery of the Norman Wells oil field. A number of modest gas discoveries have been made in the southern part of the region adjacent to British Columbia. One of these, the Pointed Mountain field has been placed on production. To the end of 1975, 18 million barrels of oil and 115 billion cubic feet of gas had been produced from the Mainland Territories. The only oil reserves in the region are those of the Norman Wells field which are estimated at 50 million barrels of recoverable oil. Oil and gas discoveries have also been made in the Eagle Plains Basin but none of these is currently considered to be economic. In addition to the discoveries in the southern part of the region and in the Eagle Plains, a significant oil show was encountered in the MacKay Range south of Norman Wells and, more recently, a gas discovery was made at Tedji Lake, some 150 miles north of Norman Wells.

Discussion. Although this basin is a continuation of the Western Canada Sedimentary Basin of the Prairie Provinces, its character changes sufficiently in the north to make its hydrocarbon potential less promising. The curves in Figure 10 indicate that the area is much more favourable for the discovery of gas than oil. It should be noted that the gas curve reflects a significant potential at a low probability. The estimates are relatively modest, but any gas could be of significance if discovered in the vicinity of the proposed Mackenzie Valley pipeline.

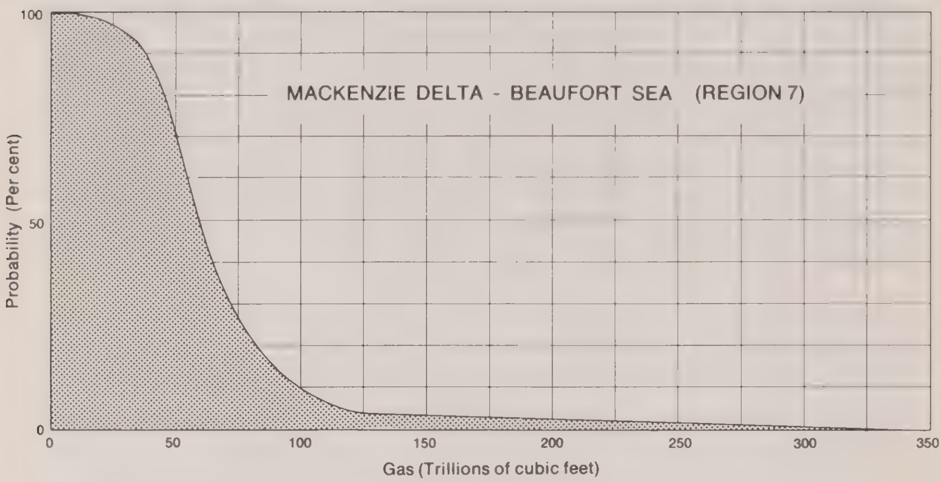
Mackenzie Delta-Beaufort Sea (Figure 11)

Location. This region (Region 7 in Figure 3) includes the onshore part of the Mackenzie Delta and that part of the offshore extending to the edge of the continental shelf at a water depth of approximately 600 feet. This region is arbitrarily terminated to the northeast in the middle of Amundsen Gulf.

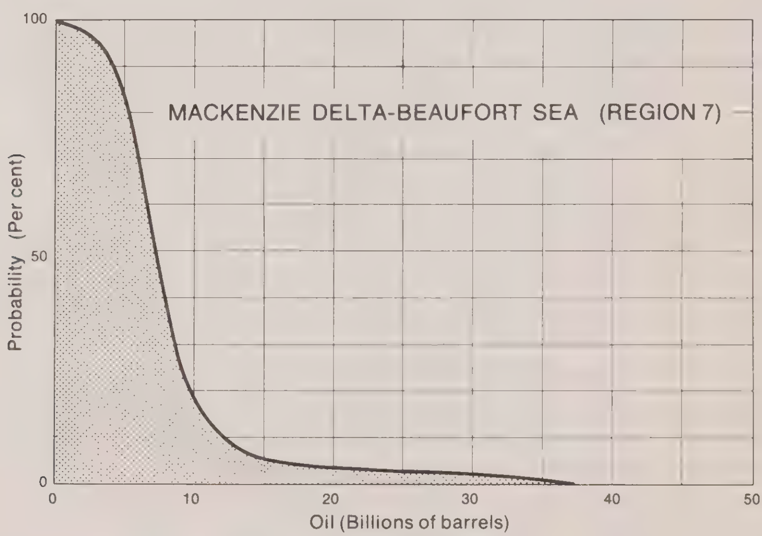
Geology. The Mackenzie Delta-Beaufort Sea region is underlain by deltaic sandstones and shales of Mesozoic and Tertiary age, which thicken rapidly northward to more than 40 000 feet, a short distance seaward from the present delta. These beds overlie faulted Paleozoic rocks stepping down steeply beneath the Mesozoic-Tertiary cover. The Paleozoic rocks rise to near the surface and are exposed in the southern part of the area in the Aklavik Arch. The Tertiary sequences contain the most important sandstone reservoirs with additional porous sandstones in the Mesozoic. A variety of structural styles within the area provide numerous hydrocarbon-trapping opportunities. These include plastic deformation of shales which have arched the overlying beds into folds, and faults which have rotated sand reservoirs to provide closure. Block-faulted Paleozoic porous carbonate rocks overlain by Mesozoic shale, also provide traps as do pinchouts of sand against impermeable basement rocks and faults in the basement rocks that have caused overlying folds.

Exploration Activity. Significant exploration activity in the Mackenzie Delta began in the 1960's, and the first hydrocarbon discovery was Atkinson in 1969.

Figure 11. Estimates of oil and gas resources of the Mackenzie Delta-Beaufort Sea region (cumulative per cent probability distribution). *Probability in per cent; **Resource in billions of barrels of oil and trillion cubic feet of gas.



Probability*	100	90	80	70	60	50	40	30	20	10	5	0
Resource**	6.5	39	45	50	55	60	65	72	81	99	121	339



Probability*	100	90	80	70	60	50	40	30	20	10	5	0
Resource**	.40	4.3	5.1	5.7	6.3	6.9	7.6	8.5	9.7	12	16	36

Since then significant discoveries have also been made at Taglu, Adgo, Ivik, Reindeer, Mayogiak, Parsons, Ya Ya, Titalik, Niglintgak, Kugpik, Kamak and Mallik. A number of estimates of the hydrocarbon discovered to date in this region have been presented as a result of the Mackenzie Valley pipeline hearings. Although these estimates show some range of opinion, there appears to be about 6.5 trillion cubic feet of gas and about 400 million barrels of liquid hydrocarbons proven to date.

Discussion. Exploration activity to date has concentrated mainly on the onshore delta prospects and the prospects that can be explored from man-made islands. The greatest remaining potential appears to lie in the offshore area, where the rate of exploration will be controlled by the ability to construct islands and the availability of specialized drill ships. The Beaufort Sea is one of the most logistically difficult areas in Canada and the rate of exploration is expected to be slow.

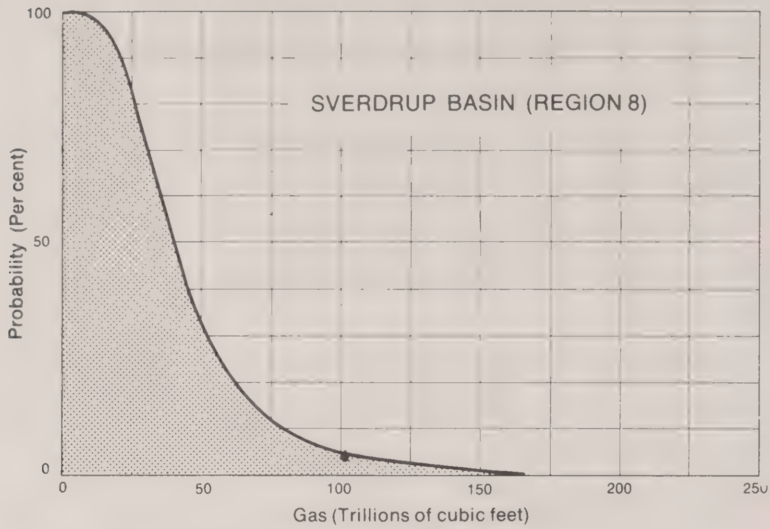
The discoveries to date as well as the estimated hydrocarbon potential indicate that the resource of the region will be dominantly gas, but there is a significant oil and NGL potential. The curves (see Figure 11) reflect the uncertainties that could be expected, considering that no drilling has occurred in a large part of the area. Because of the deltaic nature of the Tertiary deposits in this area, it is expected that there will be a large number of modest-sized pools, which will make it difficult to estimate the portion of the resources in this area that may become economic. In addition, this type of geological sequence suggests that the fields may be broken into many pools by abundant normal faults; moreover, numerous reservoirs may be stacked above one another, so that multiple pay zones may be anticipated in any one structure. Both these characteristics will add further complications to an economic analysis. Another problem in estimating the economic portion of the resources is that in many cases, both gas and oil may have to be produced from the same reservoir.

Sverdrup Basin (Figure 12)

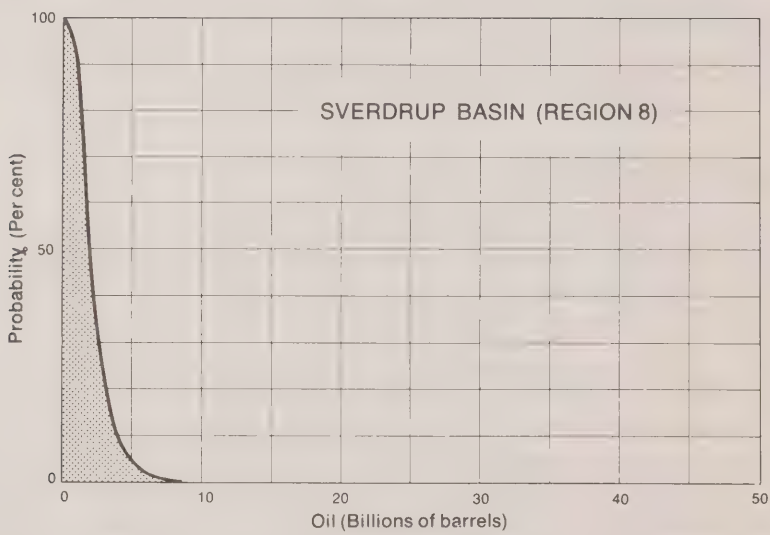
Location. This region (Region 8 in Figure 3) lies in the northern part of the Queen Elizabeth Islands. Its major axis trends in a southwesterly direction from western Ellesmere Island to northern Melville Island. The basin encompasses 121 000 square miles of which 65 000 is covered by water.

Geology. This very large sedimentary basin subsided intermittently from early Carboniferous time (about 300 million years ago), with sedimentation continuing until very recently. The basin is more than 30 000 feet deep in the centre. It is filled mostly with sandstone and shale but has some carbonates and evaporites in the basal part. The most important petroleum potential exists in the central and western parts. The hydrocarbon seems to be largely gas although geochemical studies suggest that some oil may be found in the basal rocks. To date the most important play, containing Drake Point and Hecla gas fields, is related to large, low-relief domal features along the southern margin of the basin.

Figure 12. Estimates of oil and gas resources of the Sverdrup Basin region (cumulative per cent probability distribution). *Probability in per cent; **Resource in billions of barrels of oil and trillion cubic feet of gas.



Probability*	100	90	80	70	60	50	40	30	20	10	5	0
Resource**	10	21	27	31	36	40	46	53	63	80	101	169



Probability*	100	90	80	70	60	50	40	30	20	10	5	0
Resource**	0	1.1	1.3	1.6	1.8	2.0	2.3	2.6	3.1	4.0	5.1	8.5

Other possible types of traps include faulted reservoirs, updip pinchouts of porous rocks into impervious rocks, and rocks bowed up by salt squeezed from the depths of the basin so that the porous beds are arched upwards. Unfortunately many of the largest structures, particularly in the eastern portion of this basin, were formed too late to catch hydrocarbons when they were migrating, and other structures have been breached at the surface.

Exploration Activity. Important exploration activity in this basin commenced in 1969. Wells have been drilled since then with several discoveries. Unfortunately, a number of these seem to be non-diagnostic test wells as a result of poor-quality geophysics and only a partial understanding of the geology in the earlier stages of exploration in this area. Major gas pools have been found on northern Melville Island, in particular at the Drake Point and Hecla fields. The development and extension of these fields into the offshore is still continuing. Additional gas has been found in four smaller fields in the area of King Christian Island.

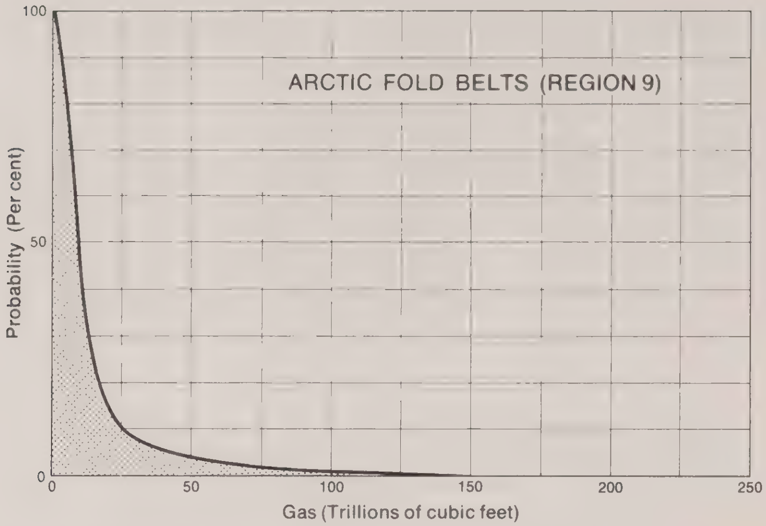
Discussion. The curve for gas shows discovered resources at 100% probability, plus undiscovered gas potential. This curve has a long tail indicating a possibility of large gas potential in the lower probability range. Although the hydrocarbons in this basin are expected to be dominantly gas, there is a significant possibility for oil as well. It is thought that the oil would come from older rocks in the shallower, marginal parts of the basin, in particular from rocks of late Paleozoic age. It is likely that most future gas discoveries will be made in the offshore areas. Because of the limited number of wells that can be drilled from the ice in winter. the delineation of these resources will be slow. The results of exploration of the eastern, highly deformed part of the basin have been discouraging and activity has shifted almost entirely to the central and western parts. That portion of the potential that may some day become an economic reserve is difficult to estimate. Unquestionably, large pools with high productivity levels will be required. Special production procedures will have to be developed for the offshore, and transportation problems will have to be resolved. The degree to which discoveries are geographically dispersed will also have a strong influence on whether they can be economically developed.

Arctic Fold Belts (Figure 13)

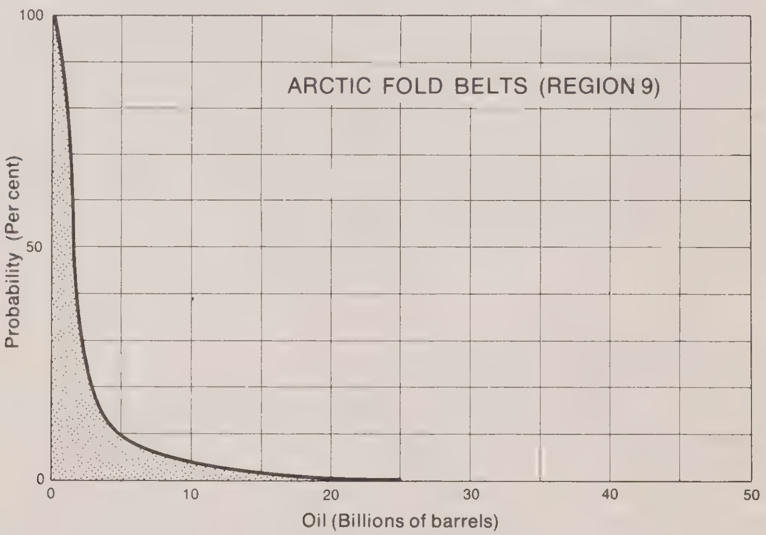
Location. This region (Region 9 in Figure 3) forms a band along the southern margin of the northern Arctic Islands bordering the north side of Viscount Melville Sound.

Geology. The Arctic Fold Belts region is underlain by a wedge of Paleozoic carbonate rocks, thickening from the thin, widespread rocks of the Northern Stable Platform region into a deeper basin to the north. This situation is similar to that of the favourable area of the Western Canada Sedimentary Basin, in that there are rapidly changing sedimentary facies, with shales that are rich source

Figure 13. Estimates of oil and gas resources of the Arctic Fold Belt region (cumulative per cent probability distribution). *Probability in per cent; **Resource in billions of barrels of oil and trillion cubic feet of gas.



Probability*	100	90	80	70	60	50	40	30	20	10	5	0
Resource**	0	2.9	5.7	8.0	9.4	11	12	14	16	26	50	150



Probability*	100	90	80	70	60	50	40	30	20	10	5	0
Resource**	0.1	.50	.95	1.3	1.6	1.8	2.0	2.3	2.7	4.3	8.4	25

rocks interfingering with carbonate reservoirs on a so-called "hingeline" of the basin. This, in most basins, is the critical area of highest potential for hydrocarbon accumulations.

The region is one of extremely complex structure that is not yet fully understood. The current exploration activity, using geophysical techniques, is providing a better understanding of the hidden structures. The most obvious structures in this region are the large east-west elongated folds formed in Late Devonian time. Reef buildups occur between the carbonates of the shelf to the south and the muds in the deeper basin of the north, and form an ideal locus for the entrapment of hydrocarbons. In the deeper part of the section, traps occur where porous beds are postulated to lie beneath Lower Paleozoic evaporites. Basal sands overlying the Precambrian may be encountered where they onlap basement arches forming possible traps. The complex structures and interesting facies relationships within this region suggest that there may be many additional as yet unconceived plays.

Exploration Activity. Only a few wells had been drilled to the end of 1975 in the Arctic Fold Belts region, but the oil discovery at Bent Horn on Cameron Island should provide an additional incentive to accelerate exploration in this region.

Discussion. The Arctic Fold Belts region is not well explored, and this is reflected in the shape of the oil and gas curves (Figure 13). Their long tails indicate that sufficient evidence is available to predict that very large resources could occur, but at a low level of confidence.

This region is likely to yield moderate quantities of liquid hydrocarbons. There are a number of possible oil and gas plays in the region, some of which have not been tested. The potential for oil has already been indicated both from geochemical studies and from the discovery on Cameron Island. This discovery is the first clear indication that oil has been generated, migrated, and accumulated in this region; this changes the uncertainties in making estimates of oil and natural gas potential. The main questions now are the extent of the reservoir and the size of the traps.

Offshore Inaccessible Areas

Location. This region (Region 10 in Figure 3) for descriptive purposes is divided into two parts: (1) the continental slopes and rises off the Scotian Shelf, Grand Banks, northeast Newfoundland and Labrador shelves; the Baffin Bay shelf and slope and the Arctic Coastal Plain Shelf; and (2) the West Coast Shelf and slope. The first part comprises areas in which the depth of water is beyond current drilling capabilities or are under ice. Exploration activities have commenced in Baffin Bay and this region will be included in the next estimates. The second part, the West Coast Shelf, is currently not available for exploratory drilling primarily due to environmental constraints.

Comment. Estimates are provided for only the West Coast Shelf. In other parts of Region 10 the only available evidence to use as a basis for estimates is

geophysical. Whether or not suitable organic facies are present in the sediments is not known. Neither is it known whether there are reservoir rocks within these regions. It is, however, probable that the Baffin Bay Shelf and the upper part of the slopes off Eastern Canada will be drilled within the foreseeable future.

West Coast Offshore. Two sedimentary basins are known off the west coast of British Columbia—the Queen Charlotte Basin lying between the Queen Charlotte Islands and the mainland, and the Tofino Basin lying off the west coast of Vancouver Island. There is also a basin on the continental slope but it is currently technologically inaccessible. Both the Queen Charlotte and Tofino basins have been tested by a number of wells but with no success. Due to environmental constraints there has been no recent exploration in the West Coast area. The following summarizes an estimate made earlier on the basis of available data. It has not been included in calculating the total Canadian oil and natural gas estimate.

Oil and Natural Gas Resources — West Coast Offshore

	90% Probability	*50% Probability*	*10% Probability*
Oil (billions of barrels)	0.02	0.02	1.0
Gas (trillion cubic feet)	0.1	1.4	6.3

ESTIMATE OF CANADA'S TOTAL CONVENTIONAL OIL AND NATURAL GAS RESOURCES, 1975

Estimates of oil and natural gas resources for nine hydrocarbon-bearing regions of Canada are given by the curves of Figure 14 and the selected values in Table 3. The offshore inaccessible areas are not included because their exploitation, using present-day technology, cannot be foreseen. As stated earlier in this report single values cannot be presented because these estimates are made by application of the theory of probability.

Again a note of caution regarding these estimates; it cannot be emphasized too strongly that what is shown are estimates of the ultimate resources for oil and gas. The portions identified as potential (or undiscovered resources) cannot be construed as reserves. Only some fraction of the potential will actually be discovered and only a fraction of that may become economic reserves if and when discovered.

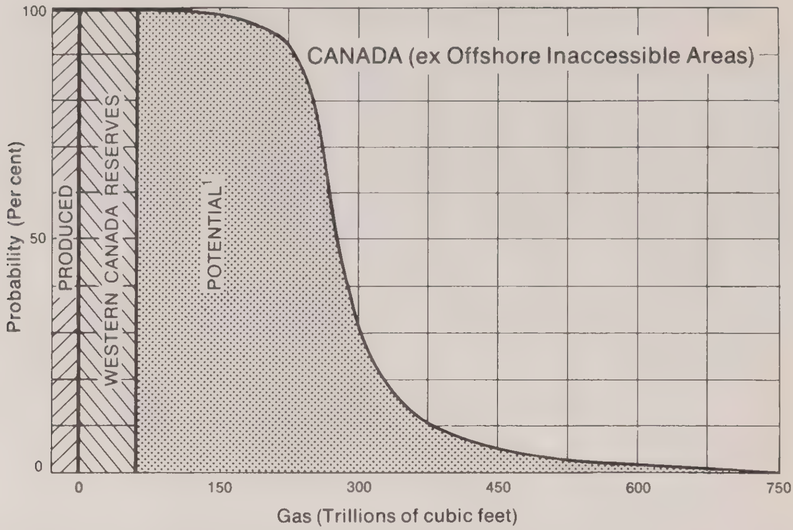
The resource estimates as presented include the remaining Western Canadian reserves, frontier discoveries and undiscovered potential oil and gas. As of year end 1975, about 85 trillion cubic feet (Tcf) of gas had been discovered in Western Canada of which 26 Tcf had been produced leaving 59 Tcf of remaining reserves. At the 100% probability level (certainty), Figure 14 also includes up to 25 Tcf of discovered natural gas in Canada's frontier regions, giving a total of 84 Tcf.

Similarly, at year end 1975, about 16.4 billion barrels of recoverable crude oil and natural gas liquids had been discovered in Western Canada of which 8.4 billion barrels had been produced leaving 8.0 billion barrels remaining reserves. Only a few hundred million barrels of crude oil and natural gas liquids are *known* to exist in the frontier regions; a figure of 8.5 billion barrels is shown in Figure 14 at the 100% probability level as the remaining liquid hydrocarbon resource for all of Canada.

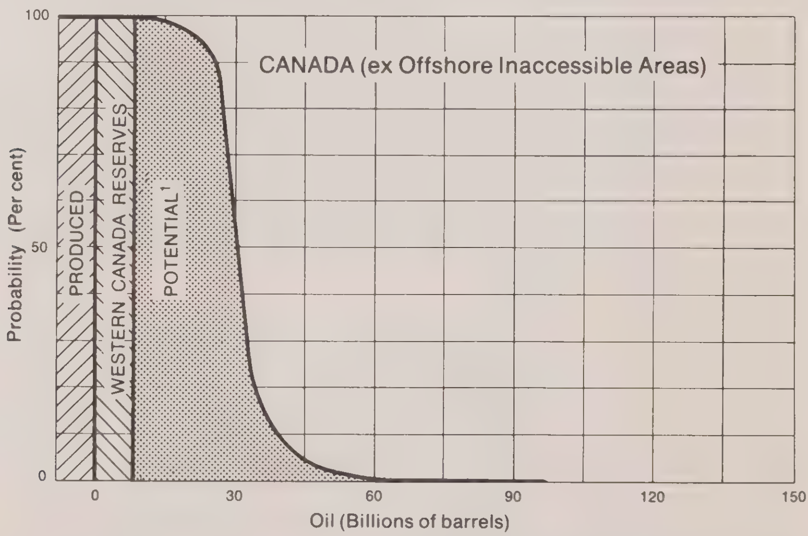
In addition to these known resources it is estimated that between about 16 and 34 billion barrels of combined crude oil and natural gas liquids remain to be discovered at the "high" (90%) and "low" (10%) probability levels respectively, about four fifths of which will be found in frontier areas. For natural gas, between 145 and 294 Tcf may exist at the "high" and "low" probability levels respectively, about nine tenths of which will be found in frontier areas. Using an approximate thermal equivalent of 6 000 cubic feet of natural gas per barrel of oil, the above estimates indicate that Canada's remaining oil and gas potential is expected to be dominantly gas.

The Western Canada Sedimentary Basin (Table 3) may contain a total of between about 11 to 14 billion barrels of liquid hydrocarbons and 89 to 107

Figure 14. Estimates of oil and gas resources of Canada excluding inaccessible offshore areas (cumulative per cent probability distribution). *Probability in per cent; **Resource in billions of barrels of oil and trillion cubic feet of gas.



Probability*	100	90	80	70	60	50	40	30	20	10	5	0
Resource**	84[2]	229	243	255	266	277	289	305	328	378	433	750



Probability*	100	90	80	70	60	50	40	30	20	10	5	0
Resource**	8.5[2]	25	26	27	29	30	31	33	36	43	51	97

[1]Includes discovered resources in frontier regions.
[2]Includes Western Canada reserves plus discovered resources in frontier regions. Past production is not included.

Table 3

SUMMARY OF OIL AND NATURAL GAS RESOURCES OF CANADA — 1975*
(Remaining Reserves, Discovered Resources and Undiscovered Potential)

	Likelihood of Existence		
	"High" 90% Probability	*50/50 Chance 50% Probability*	*"Low" 10% Probability*
		Oil Resources (billions of barrels)	
REGION			
Atlantic Shelf South	1.2	1.9	3.0
Labrador-East Newfoundland Shelf	1.7	2.6	4.5
Northern Stable Platform Basins	0.01	0.6	3.2
St. Lawrence Lowlands	0.04	0.09	0.2
Western Canada	10.9	11.7	13.5
Mainland Territories	0.3	0.5	1.0
Mackenzie Delta-Beaufort Sea	4.3	6.9	12
Sverdrup Basin	1.1	2.0	4.0
Arctic Fold Belts	0.5	1.8	4.3
Total Canada (Accessible Regions)	25	30	43
		Gas Resources (trillions of cubic feet)	
REGION			
Atlantic Shelf South	8.6	13.2	20
Labrador-East Newfoundland Shelf	18	26.7	45
Northern Stable Platform Basins	0.4	2.3	12
St. Lawrence Lowlands	0.7	1.4	3.2
Western Canada	89	97	107
Mainland Territories	6.0	9.7	20
Mackenzie Delta-Beaufort Sea	39	60	99
Sverdrup Basin	21	40	80
Arctic Fold belts	2.9	11	26
Total Canada (Accessible Regions)	229	277	378

NOTE: These columns do not total arithmetically to the Canada totals because individual curves must be summed using a statistical technique described elsewhere in the report.

*Prepared by Geological Survey of Canada.

trillion cubic feet of natural gas at the 90% and 10% probability levels. (These figures, of course, exclude the large hydrocarbon accumulations of the Alberta oil sands deposits.)

In terms of ultimate potential crude oil and natural gas liquids, therefore, the estimates indicate that there is a very low probability that the frontier and other regions of Canada could exceed the relatively prolific Western Canada

sedimentary basin taking account of past production. Indeed, only the Mackenzie Delta-Beaufort Sea region would appear to have a reasonable probability of containing oil potential rivalling the *remaining* resources in Western Canada. Such large potential is estimated to have less than 10% probability of occurrence. Further, the bulk of these resources, if discovered, is expected to be found under the shifting pack-ice of the Beaufort Sea.

In terms of natural gas potential, the Sverdrup Basin, the Mackenzie Delta-Beaufort Sea and the Labrador-East Newfoundland Shelf regions may rival Western Canada. Here again, however, the probability that one of these basins could exceed the *remaining* gas resources in Western Canada is in the range of only 10% or less. In each of these areas also, all or a large proportion of total potential is expected to be found offshore under polar pack-ice or in iceberg-infested waters. Only at very low probabilities, in the range of 2-3%, could the Labrador-East Newfoundland Shelf region contain natural gas potential comparable to the remaining gas resource in Western Canada.

Estimates for the four regions of Canada having the largest potentials are shown in Figures 15 and 16. The curves for the mature Western Canada region differ considerably from those of the frontier basins in being very steep with a short tail reflecting the relatively mature state of development in that area. Although the median value exceeds those of the frontier regions by a large factor, the range of the undiscovered potential estimates is correspondingly much less than that of any of the frontier regions.

The shapes of the curves for the three frontier regions are similar over most of the range of estimates, although there are differences below the 5% probability levels. Natural gas potentials, and to a lesser extent oil potentials for each of the frontier regions depicted could be very large although the graphs indicate that there is an extremely low probability of such an outcome. If, however, nature were to fortuitously combine such factors as the presence of adequate source beds, appropriate timing in structure formation and hydrocarbon migration, reservoir porosity and seal, along with subsequent preservation of the basin, such potentials might be realized. The rarity of such occurrences, however, is reflected in the very low probabilities assigned to such circumstances.

Figure 15. Estimates of gas resources for major regions having potential for new discoveries (cumulative per cent probability distribution).

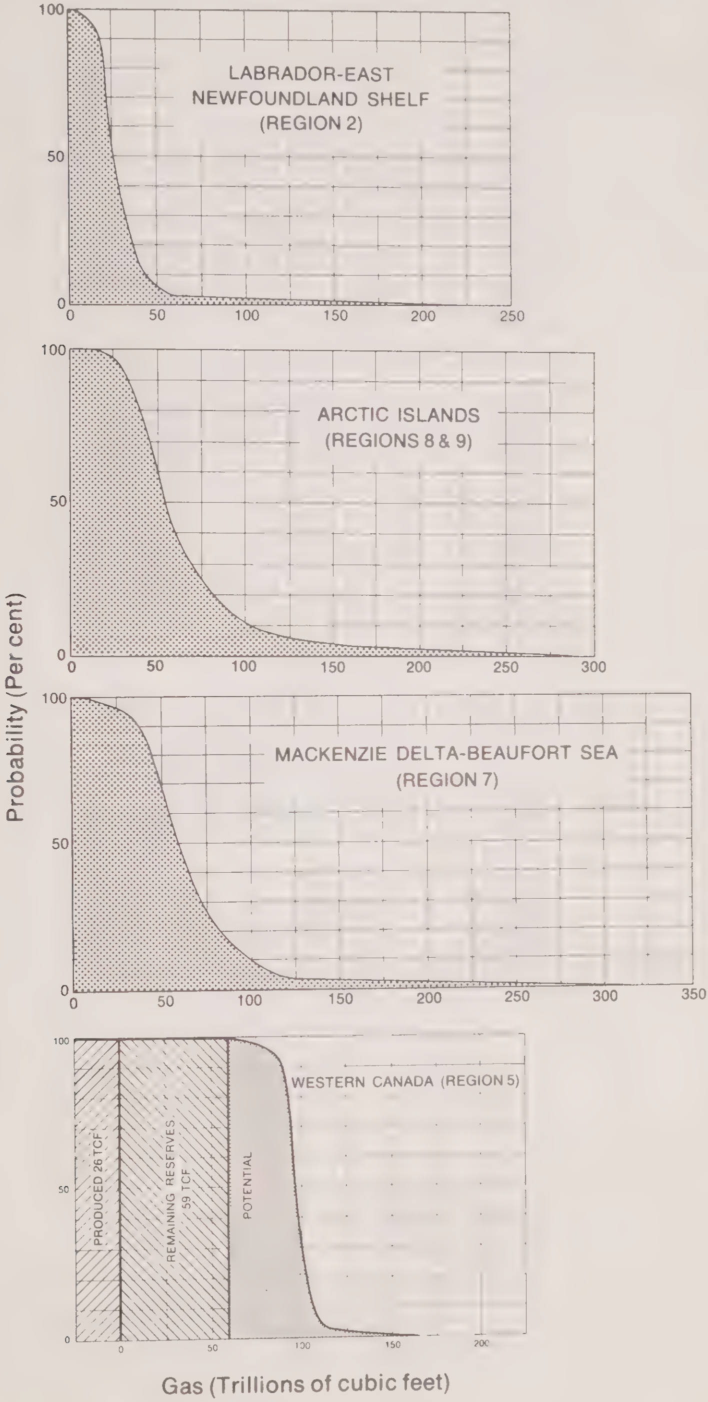
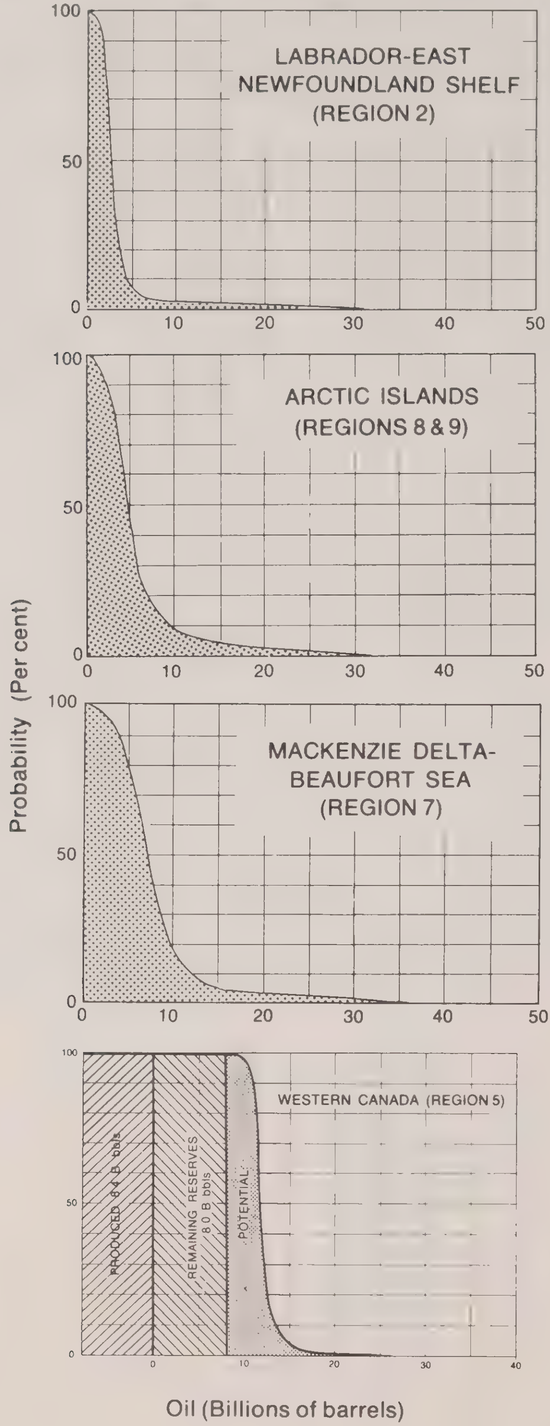


Figure 16. Estimates of oil resources for major regions having potential for new discoveries (cumulative per cent probability distribution).



COMPARISON WITH OTHER RESOURCE ESTIMATES

Comparing estimates is difficult and sometimes misleading, but it is a necessary and an inevitable exercise. Comparisons are made difficult by the failure of many estimators to state clearly the basis upon which their estimates have been prepared. It is necessary to know exactly what is being estimated: Does it include past production? Are reserves included? Are the quantities technically recoverable or in-place? If they are technically recoverable, are they economically recoverable? Has an economic cutoff been used? If so, at what level? Are natural gas liquids included? and so on.

One of the most important considerations in any estimate, and one which is frequently omitted, is reference to the method used. Without this, the reader is unable to distinguish between a rough guess about the resources in an area and a very carefully documented prospect-by-prospect analysis. Single-number estimates are particularly difficult to use if one does not know the level of probability attached. Single-number estimates may reflect industry expectations of high-risk exploration possibilities. On the other hand, a single-number estimate may be a "most likely" value which is smaller but reflects a greater likelihood of occurrence.

Previous EMR (Geological Survey of Canada) Estimates

Two resource estimates were included in *An Energy Policy for Canada,* published in 1973 by the Department of Energy, Mines and Resources. The first of these, made in 1972, was a first attempt using a volumetric method. The second, made in 1973, used frequency distributions of estimates in an effort to express quantities of hydrocarbons in association with the probability of their actual existence.

In the current report, changes in estimates of both oil and gas for Canada are generally downward from the 1973 estimates. These changes are the result of new information generated by exploration, increased access to information and improvements in methodology. In addition, the present report does not include estimates for the inaccessible continental slopes and rises (Region 10). This exclusion is responsible for approximately one third of the reduction from the previous estimates.

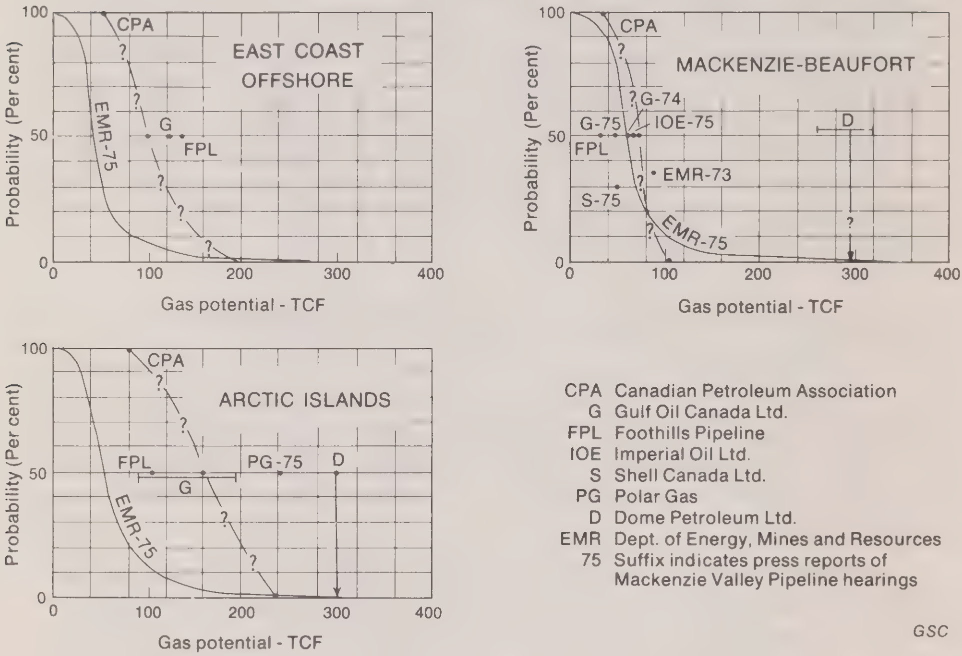
Other Estimates

Various estimates of gas resources that have been released at National Energy Board hearings or in the press are shown (Figure 17) for important frontier areas of Canada. The 1975 EMR estimates are shown for comparison. Recent comparable estimates for oil are not available. In Figure 17 where only a single unqualified number was available it has been plotted at the 50% probability level of the graph. The Canadian Petroleum Association (CPA) expressed figures for

all of the frontier areas in the form of a range of estimates with high, low and average values, and these have been plotted in the form of a curve. Gulf Oil Canada Limited gave an estimate in the form of a range, but without specifying any probabilities attached to it; it is shown therefore at the 50% probability level.

Figure 17 is perhaps most useful as an indication of the difficulty encountered in making valid comparisons of various estimates. It is noteworthy that most of these estimates fall within the range of the EMR estimates. It is possible that the opinions expressed would be in close agreement if their likelihood of occurrence were known.

Figure 17. Comparison of other estimates of gas resources, with current EMR estimate shown as solid line.



CONCLUSIONS

1. The bulk of the hydrocarbon potential (mainly gas) lies in the three frontier regions, the Mackenzie Delta-Beaufort Sea, Arctic Islands and Labrador Shelf regions which are expensive and difficult to explore. Additions to the short-term supply will have to come largely from the Western Canada Sedimentary Basin.
2. For the frontier regions, the bulk of the potential is likely to occur in offshore areas with very hostile environments and attendant high costs, logistical problems, and environmental risks. This potential is considered unlikely to add materially to the short- and medium-term supply.
3. Significant undiscovered resources remain in the Western Canada Sedimentary Basin. These will occur mostly in the deeper part of the basin, and in low productivity gas sands, and in heavy oils in the shallower part of the basin.
4. The Mackenzie Delta-Beaufort Sea area is an above-average petroleum province. The largest part of the potential in this area is probably in the offshore region. Significant volumes of gas have already been discovered in the Mackenzie Delta and there are indications that there may also be large quantities of liquid hydrocarbons.
5. A large potential for gas exists in the Sverdrup Basin and in the Arctic Fold Belts of the Arctic Islands. The largest part of this potential is also in the offshore region.
6. The major portion of petroleum potential on the eastern seaboard lies beneath the Labrador Shelf.

Part II

RESERVES AND RESOURCES OF THE OIL SANDS DEPOSITS OF ALBERTA

INTRODUCTION

The Alberta oil sands deposits have been delineated through evaluation of data collected on some 5 000 drillholes. They are categorized according to the geographical area of occurrence and by geological units as follows (see also Figure 18):

Geographical Area and Deposit Name	*Geological Unit(s)*
Athabasca	Wabiskaw-McMurray
Peace River	Bluesky-Gething
Cold Lake A	Grand Rapids
Cold Lake B	Clearwater
Cold Lake C	McMurray
Wabasca A	Grand Rapids
Wabasca B	Wabiskaw
Buffalo Head Hills	Bluesky-Gething

Reserves estimates have been prepared for each deposit on the basis of reservoir mapping, taking into account fluid saturations, sand porosity and formation thickness. Volumetric estimates are presented of crude bitumen-in-place, bitumen recoverable and synthetic crude oil for those deposits in the Athabasca area under less than 150 feet overburden which are considered to be accessible using mining techniques.

An estimate is also made of the ultimate recovery of bitumen and the resulting synthetic crude oil recovery from both mining and *in situ* recovery processes.

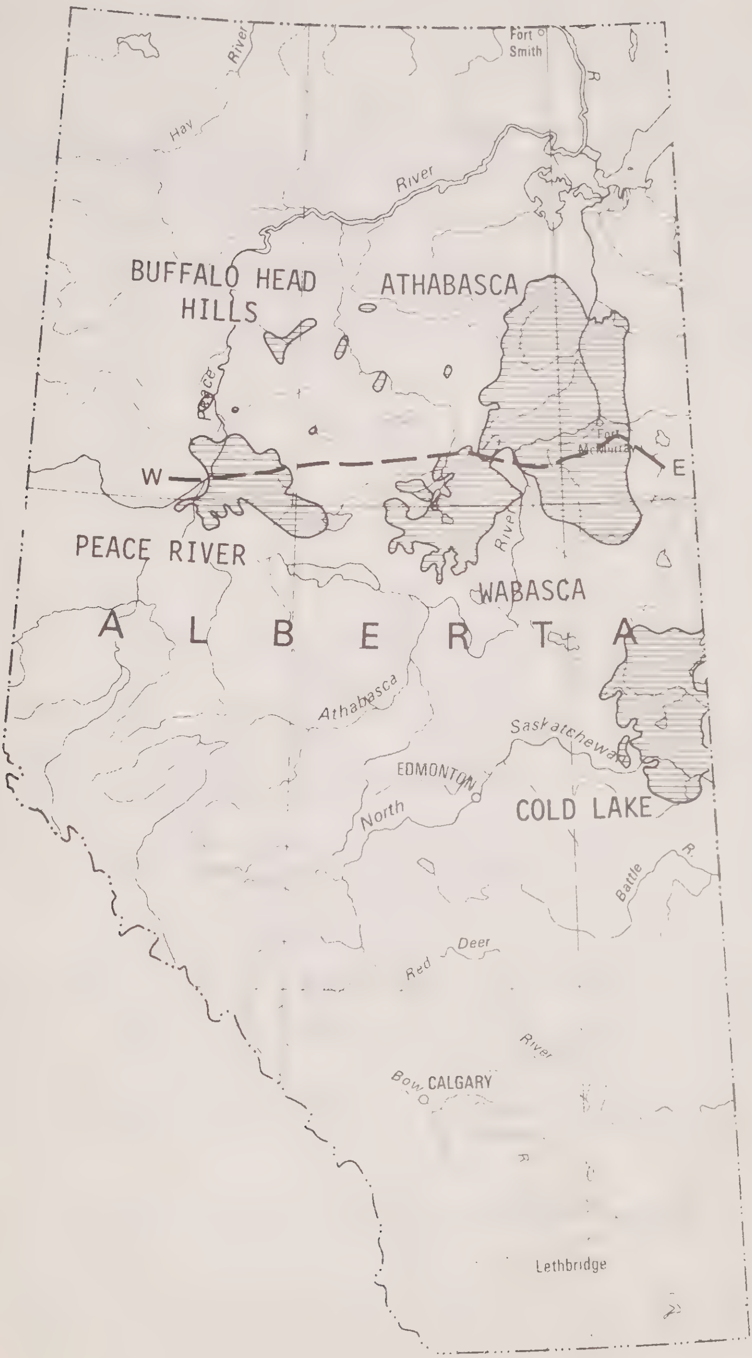
TERMINOLOGY

Crude Bitumen — A naturally occurring viscous mixture, mainly of hydrocarbons heavier than pentane, that may contain sulphur compounds, and that in its naturally occurring viscous state is not recoverable at an economic rate through a well.

In-Place Reserves — The total resource in a deposit less any portion of it deemed unrecoverable by any foreseeable technology or under any foreseeable economic circumstances.

NOTE: The estimates presented in this section have been furnished by the Alberta Energy Resources Conservation Board (ERCB). The text is modified slightly from that prepared by C. Outtrim of the ERCB.

Figure 18. Oil sands deposits in Alberta. The dashed line "W---E" is the trace of a generalized cross-section (Figure 20).



Oil Sands — Sands and other rock materials that contain crude bitumen and other associated mineral substances.

Oil Sands Deposit — A natural reservoir containing or appearing to contain an accumulation of oil sand separated or appearing to be separated from any other such accumulation.

Proved Reserves — Those reserves specifically delineated by drilling, ditching, running adits, testing or production, plus a judgement portion of those further contiguous reserves which are generally delineated by geological, seismic or similar information and which can reasonably be counted upon.

Synthetic Crude Oil — A mixture, mainly of pentanes and heavier hydrocarbons, that may contain sulphur compounds, that is derived from crude bitumen and is liquid at the conditions under which its volume is measured or estimated.

SUMMARY OF RESERVES ESTIMATES

The details of the reserves estimates are contained in Table 4. Columns 10 through 14 contain the estimates of the recoverable synthetic crude oil as fractions of the in-place and as recoverable volumes of crude bitumen, with initial, produced and remaining volumes. The remaining synthetic crude oil reserves recoverable from mineable sands are estimated to be 26.5 billion barrels. These figures reflect 1975 annual production of 22.5 million barrels of crude bitumen and 15.8 million barrels of synthetic crude oil.

The first five columns of Table 4 give the estimates of the areal extent and the ultimate in-place reserves which are estimated to be 953 billion barrels of bitumen. Recovery of crude bitumen from the deposits with overburden in excess of 150 feet will probably take place by one or a combination of different *in situ* processes, some of them in advanced stages of experimentation. However, it would be premature to place such recoverable crude bitumen, and the synthetic crude oil which could be recovered therefrom, in the proved category at this time.

It is anticipated that the ultimate in-place reserves of crude bitumen in the presently delineated oil sands deposits in Alberta will amount to some 1 000 billion barrels. In addition, the current assessment of deposit characteristics, potential recovery, and upgrading techniques result in an estimate of 330 billion barrels of ultimate recoverable reserves of crude bitumen and 250 billion barrels of ultimate recoverable reserves of synthetic crude oil.

Table 4

THE PROVED RESERVES OF CRUDE BITUMEN AND SYNTHETIC CRUDE OIL OF THE OIL SANDS OF ALBERTA, 1975

	Crude Bitumen									Synthetic Crude Oil					
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
										Recoverable From					
Deposit	*Areal Extent*	*Average Pay Thickness*	*Average Saturation*	*Saturation Cut-off*	*Initial In Place*	*Recovery*	*Initial Recoverable*	*Cumulative Production*	*Remaining Recoverable*	*Initial In Place Crude Bitumen*	*Recoverable Crude Bitumen*	*Initial Recoverable*	*Cumulative Production*	*Remaining Recoverable*	*Remarks*
	(thousand acres)	*(feet)*	*(fraction by weight)*	*(fraction by weight)*	*(Bstb)*	*(fraction by weight)*	*(Bstb)*	*(MMstb)*	*(MMstb)*	*(fraction by volume)*	*(fraction by volume)*	*(MMstb)*	*(MMstb)*	*(MMstb)*	
Athabasca Surface Mineable	490	100	0.10	0.02	74	0.51	38	159	37 800	0.51	0.40	26 600	113	26 500	Evaluated in 1963[1] and 1972
In situ	5 260	70	0.10	0.02	553	—	—	—	—	—	—			—	
Cold Lake A	1 080	53	0.08	0.03	118	—	—	—	—	—		—			
Cold Lake B	650	40	0.08	0.03	33	—	—	—	—			—	—	—	Evaluated in 1973[2]
Cold Lake C	710	16	0.08	0.03	14	—	—	—	—		—	—	—	—	Evaluated in 1973[2]
Buffalo Head Hills	159	7	0.05	0.02	1	—	—	—	—	—		—	—	—	Evaluated in 1963[1]
Peace River	1 606	45	0.07	0.03	75	—	—	—	—		—	—		—	Evaluated in 1974[3]
Wabasca A	1 342	25	0.09	0.03	48	—	—	—	—	—	—	—	—	—	Evaluated in 1976[4]
Wabasca B	1 721	20	0.07	0.03	38	—	—	—	—	—		—	—	—	Evaluated in 1976[4]
TOTAL	12 378*				953		38	159	37 800			26 600	113	26 500	

[1] Oil and Gas Conservation Board, 1963. *A Description and Reserve Estimate of the Oil Sands of Alberta*. Calgary, Alberta.

[2] Energy Resources Conservation Board, 1973. *Geology and Proved In Place Reserves of The Cold Lake Sands Deposits*. ERCB Report 73-L-Geol. Calgary, Alberta.

[3] Energy Resources Conservation Board, 1974. *Geology and Proved In Place Reserves of The Peace River Oil Sands Deposits*. ERCB Report 74-R. Calgary, Alberta.

[4] Energy Resources Conservation Board, 1976. *Geology and Proved In Place Reserves of The Wabasca Oil Sands Deposits*. ERCB Report 76-A. Calgary, Alberta.

*Not additive because of areal overlap between deposits.

NOTE—Weight to volume conversion for the Athabasca Deposit is 1.92. For the Peace River, Wabasca A and Wabasca B Deposits, they are porosity-dependent functions having weighted averages of 2.22, 2.12 and 2.16 respectively. For the other deposits it is estimated to be 2.0. Bstb is equivalent to billion barrels. MMstb is equivalent to million barrels.

METHODS OF ESTIMATION

Proved In-Place Reserves of Crude Bitumen

Thickness and saturation cut-off criteria were employed to exclude from the in-place reserves crude bitumen considered to be unrecoverable by foreseeable technology or under foreseeable circumstances. The cut-off criteria usually applied for the determination of in-place reserves were:

1. Saturated sand lenses which are less than 5 feet thick and which are vertically or horizontally isolated from deposits of greater thicknesses.
2. Saturated sand lenses with a crude bitumen saturation less than 3 per cent by weight.

Proved Recoverable Reserves of Crude Bitumen

An assessment has been made only of the proved recoverable reserves for those portions of the Athabasca deposits which are amenable to surface mining methods. This limits the areas of interest to those in which overburden depths do not exceed 150 feet.

The recoverable reserves estimates are based entirely on 1972 criteria. Thus only sands having a thickness of 5 feet or greater and a bulk weight saturation of 5 per cent or greater are considered. Also only those sands having a net oil column necessary for an overburden to oil sand thickness ratio of 1.0 or less (based on an average oil sand saturation determined for various overburden categories) are used in the appraisal.

Economically recoverable reserves of crude bitumen and synthetic crude oil of individual oil sand leases being proposed for development are presently being evaluated using a criterion established in 1974, but reserves figures are not yet published on this basis. This criterion employs a relationship between the total waste thickness to plant feed thickness ratio and the specific plant feed saturation. The equation which represents the break-even economic conditions is:

Economic when

$$\frac{S}{1 + 0.9\,(w/o)} \geqslant 5$$

Uneconomic when

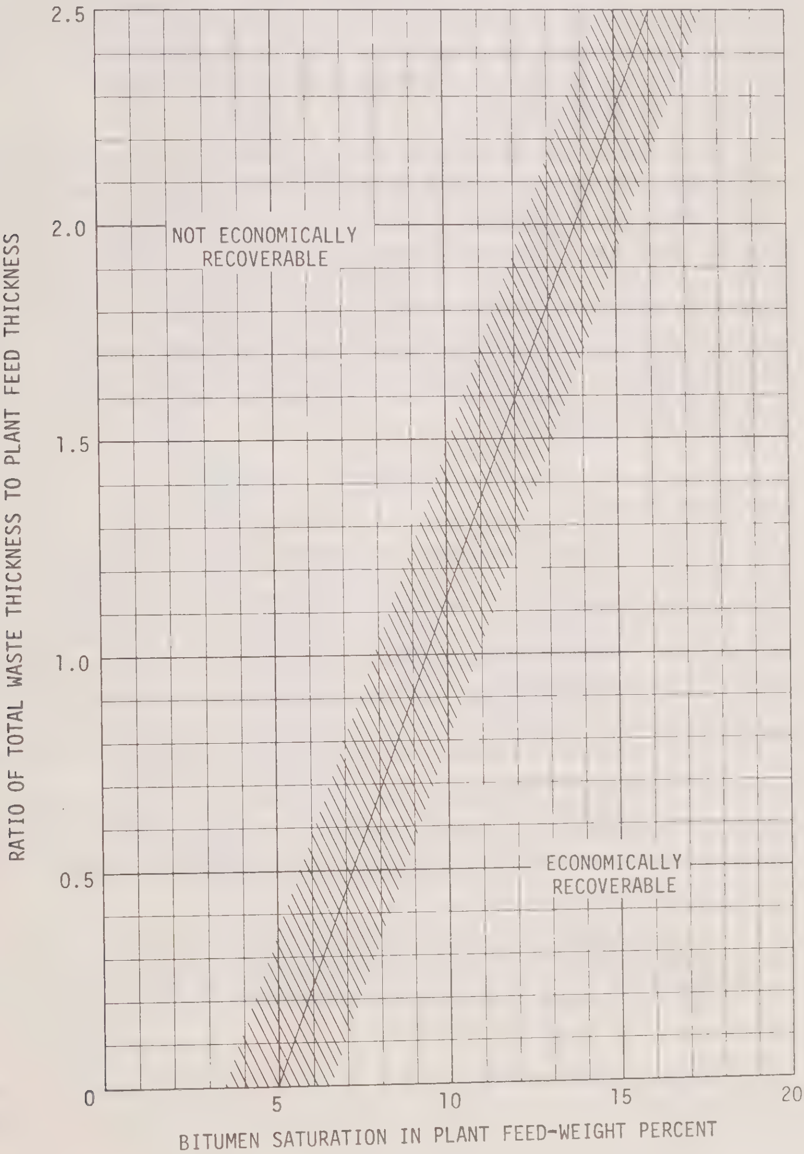
$$\frac{S}{1 + 0.9\,(w/o)} < 5$$

where S = the saturation in weight per cent,
w = total waste thickness,
o = total plant feed thickness.

It is recognized that economic conditions will change with time and improving technology. Consequently, a range of conditions which may represent the economic viability of a specific area has been identified. Figure 19 is graphic representation of the 1974 criterion for surface mineability and the range of possible break-even conditions.

Application of the 1974 recoverability criteria is not likely to alter the recoverable reserves based on the 1972 criteria and presented herein to any significant extent.

Figure 19. Criterion for oil sands economically recoverable by mining.



GEOLOGY OF THE ALBERTA OIL SANDS

Regional Geological Setting

Sedimentary rocks of Cretaceous age are widely distributed in the western, Arctic and offshore regions of Canada but apparently only in northern Alberta were geological conditions conducive to the widespread generation, migration and entrapment of heavy oil deposits in reservoirs of that age. Sedimentation processes during the Early Cretaceous in Western Canada were complex. The character of the sands and associated shales indicate that these were derived from two principal sources: (1) the Canadian Shield lying to the east, and (2) rising highlands of the Cordillera to the west. From these two widely separated source areas the sediments were transported by fluvial (stream) processes into the Alberta Basin, where they were deposited in a variety of continental deltaic and marine environments.

A large part of the heavy oil sands deposits of Alberta is contained within the Lower Cretaceous Mannville Group which has been subdivided into McMurray, Clearwater and Grand Rapids formations in that ascending order of succession. The Peace River deposit occurs in sands equivalent to the Mannville, but which is referred to the Gething and Bluesky formations. The relationships of these units and the location of the largest oil sands deposits are shown in a generalized cross-section (Figure 20) which extends from the western border of the Peace River deposit to the eastern limit of the Athabasca deposit just south of Fort McMurray (Figure 18).

Peace River Area

This deposit is located in north-central Alberta as shown on Figure 18.

The crude bitumen reserves of the Peace River area occur in the Bluesky and Gething formations of Lower Cretaceous age. These formations comprise a clastic sequence lying unconformably on subcropping strata of Jurassic, Permian and Mississippian ages. The sequence pinches out against Mississippian carbonates to the northeast with the Bluesky sediments onlapping those of the Gething Formation. Depth of burial ranges from 1 500 feet to 2 600 feet.

Structurally, the deposit is simple, with the upper Bluesky contact dipping southwest at approximately 20 feet per mile. The reservoir sands are progressively less saturated with crude bitumen and more saturated with water downdip from the pinchout edge.

The Bluesky Formation consists of well sorted and generally well developed, fine- to medium-grained, glauconitic sands interpreted to be either a marine facies equivalent to uppermost Gething beds, or a marine reworking of Gething sediments.

The Gething Formation consists of poorly sorted, discontinuous sandstones interstratified with shales and siltstones. Minor coal and chert-pebble bands

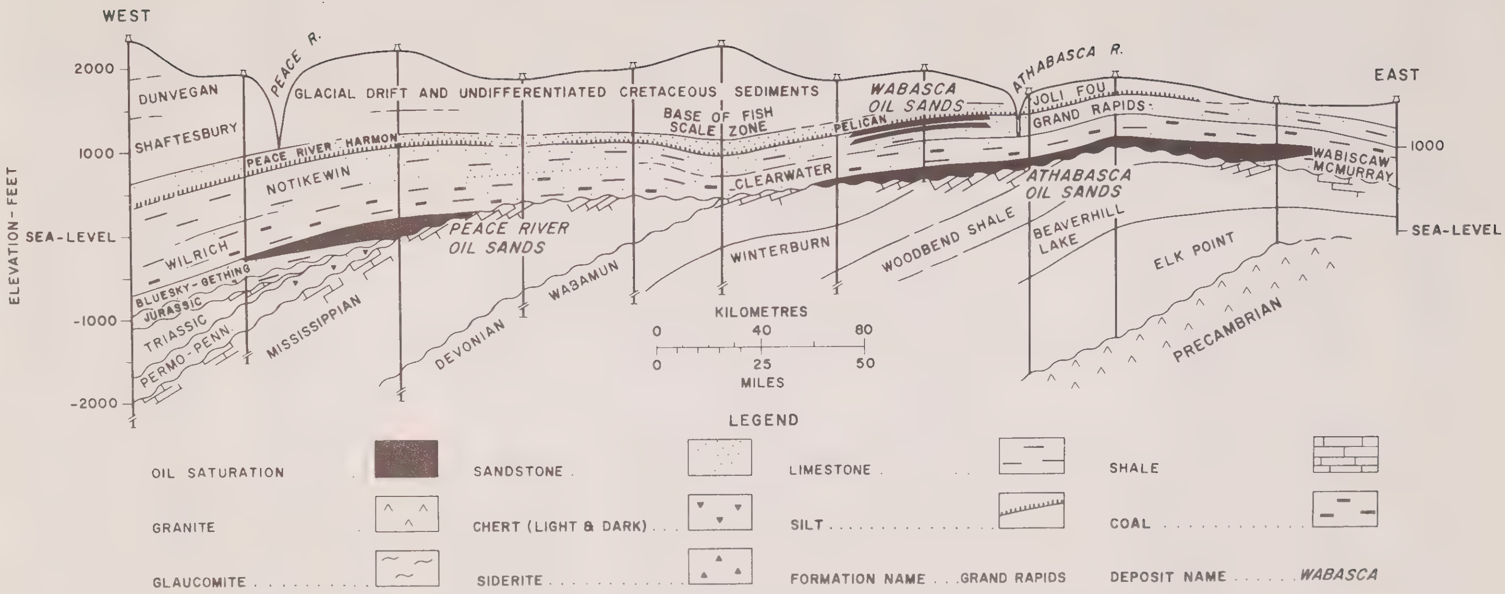


Figure 20. Schematic cross-section (see Figure 18) between the western boundary of the Peace River deposit and the eastern boundary of the Athabasca deposit south of Fort McMurray (after Pow *et al.*, 1963, *in* Athabasca Oil Sands, *Alta. Res. Council*, Info. Ser. No. 45).

occur in the section. The formation is interpreted to have a westerly source and to have been deposited in an alluvial plain environment.

The massive sands of the main trends are loosely consolidated to unconsolidated with some porosities exceeding 30 per cent and averaging 27 per cent for clean, well sorted sections. Sands away from the main trends are discontinuous, shaly and show varying degrees of compaction. Porosity for these sands averages 23 per cent. Crude bitumen saturations vary considerably, but may exceed 80 per cent of pore volume for well saturated sections. The API gravity of the crude bitumen is also quite variable with typical values being in the range of 6° to 15° API.

Wabasca Area

The Wabasca A and B Deposits are located in northeast Alberta (Figure 18).

The Mannville strata of the Wabasca area are underlain by Paleozoic strata of the Grosmont, Winterburn, Wabamun and Banff formations. Remnants of channels have been instrumental in isolating Paleozoic strata favourable for the accumulation of hydrocarbons.

The McMurray Formation, an erratic and discontinuous distribution of sands and shales, resulted from a deposition that filled the erosional channels. Crude bitumen deposits within these sands are of minor importance.

The Clearwater Formation constitutes a sequence of sands and shales which is approximately 400 feet thick. The lowermost glauconitic unit—the Wabiskaw Member—consists of reworked McMurray sediments. This unit is the only Clearwater sand in the Wabasca area that contains significant reserves of crude bitumen. This has been designated the Wabasca B Deposit.

The Grand Rapids Formation attains a thickness of 300 feet in this area and consists of predominantly massive nearshore sands that contain the crude bitumen reserves of the Wabasca A Deposit.

Athabasca Area

The Athabasca deposits are also in northeastern Alberta (Figure 18).

The Mannville strata of the Athabasca area are underlain by sediments of Devonian age which comprise the Waterways, Cooking Lake, Ireton and Grosmont formations.

The McMurray Formation unconformably overlies the Devonian rocks and is a combination of clastic materials having sources both in the Precambrian rocks east of the basin and in the igneous rocks of the Cassiar-Omineca and Nelson regions of central British Columbia. The majority of the crude bitumen reserves of this area are contained in the McMurray Formation and the Wabiskaw unit of the Clearwater Formation.

The McMurray Formation thickens in a northeasterly direction from its pinchout edge to a maximum of over 200 feet. In isolated locations its thickness reaches 275-300 feet.

The more continuous and widespread upper beds of the McMurray Formation consist mainly of horizontally bedded medium to very fine quartz sand with lenticular interbeds of silts and shales. There are occasional coal and plant remains.

The lower member of the McMurray occupies the deeper depressions of the Paleozoic surface and contains lenticular beds of coarse-grained, well rounded quartz sand with feldspar fragments and residual clay derived from the underlying limestone.

Cold Lake

The Cold Lake Deposits are in east-central Alberta (Figure 18).

The crude bitumen deposits of the Cold Lake area are contained in the McMurray, Clearwater and Grand Rapids formations. The McMurray deposits are discontinous and are sporadically distributed between townships 52 and 67. These deposits conform to the Paleozoic lows. The bituminous sands of the Clearwater Formation are fairly continuous and massive. They lie primarily between townships 60 and 68. The Grand Rapids Formation is divided into two identifiable oil sand accumulations. The Lower Grand Rapids deposits are relatively continuous and extend from townships 53 to 68. Those of the Upper Grand Rapids are fairly uniform and continous and are found between townships 54 and 66. In the east-west direction the deposits are concentrated between the Fourth Meridian and Range 10 west.

The Mannville Group in the Cold Lake area lies unconformably on the Woodbend or Beaverhill Lake Group of Devonian age and is overlain disconformably by marine deposits of mid-Cretaceous age. The regional dip is southwesterly. Locally, however, a syncline exists in the Mannville which results in a gentle eastward dip. Near the Fourth Meridian this syncline terminates the eastward extent of the oil sands deposits.

The McMurray Formation is an essentially nonmarine quartz sandstone of variable thickness. The thickness ranges from 200 feet in the Paleozoic lows to 20 feet over the Paleozoic high. The formation thins from north to south in the Cold Lake deposits area and is transitional vertically into the marine Clearwater Formation.

The Clearwater Formation is a salt-and-pepper, marine sequence with some glauconitic members. It is gradational in thickness and ranges from 20 feet in the south to over 200 feet in the north. It is also more shaly in the southern parts.

The Upper and Lower Grand Rapids members are a nonmarine sequence of feldspathic and salt-and-pepper sandstones and some thin coal beds. The combined thickness ranges from 200 feet in the north to 400 feet in the south.

CURRENT AND PLANNED DEVELOPMENT

The current development of the oil sands deposits by surface mining is in areas where waste to plant feed thickness ratios and the crude bitumen saturations are most attractive. Similarly the experimental projects related to recovery of the deeply buried bitumen are underway in areas where the sands have good crude bitumen saturations and are relatively thick and continuous.

Commercial Projects

Great Canadian Oil Sands Limited (GCOS). This company is presently operating a mining extraction and upgrading facility on Bituminous Sands Lease 86. It holds an approval which allows for production of 65 000 barrels of synthetic crude oil per day. It began production in 1967 at rates of approximately 30 000 barrels per day. In 1975 production rates have averaged 43 000 barrels of synthetic crude oil per day.

Syncrude Canada Ltd. (Syncrude). This company is presently constructing its facilities and is expected to begin production in 1978. Syncrude has received approval from the Alberta Government for production of 125 000 barrels of synthetic crude oil per day. This production rate is not expected for a number of years. Maximum production will be attained through a series of programs requiring between three and six years to complete which are designed to remove existing bottlenecks.

Other Projects. In addition to GCOS and Syncrude, three other projects are currently planned. These are the Shell Canada 100 000 barrel-per-day scheme, the Petrofina *et al.* scheme for 122 000 barrels per day and the Home-Alminex proposal for production of 103 000 barrels of synthetic crude oil per day. However, little work is proceeding on these projects pending improved economic conditions and clarification of government policy respecting oil sands development.

Experimental Projects

There are a total of fifteen active and/or approved experimental schemes in the oil sands deposits. Four are in the Athabasca Oil Sands Deposit, nine in the Cold Lake Oil Sands Deposit, one in the Peace River Oil Sands Deposit and one in the Wabasca Oil Sands Deposit.

The experimental recovery techniques being employed for sands having depths of burial greater than 150 feet involve the use of cased wells drilled to the oil sand, and are referred to as *in situ* techniques. The earliest *in situ* experimental work was conducted in 1957 and since then some 42 separate projects have been undertaken or are still in operation.

These tests have and are using a variety of methods for reducing the crude bitumen viscosity to promote its mobility and allow for the use of conventional wellbore production equipment. Heat is often introduced to the formation by

injected steam or it may be produced in the formation through ignition of a portion of the bitumen. In the latter process, air is injected into the formation to sustain combustion and to form several types of propagating heat fronts. These include a steam front (formed by vaporization of formation waters, 150-200° C) and a distillation front (a zone where the lighter hydrocarbons are driven off of the crude bitumen leaving the heavier ends normally a residual coke, 200-250° C). The combustion front then follows. (The injected air oxidizes the residual coke forming a very high temperature zone, 700° C.)

Other more exotic recovery techniques have been proposed whereby solvents, aqueous solutions, bacteria and other substances would be injected into the formation to promote the reduction of viscosity.

CONCLUSIONS

The Alberta Energy Resources Conservation Board believes that the deposits are fairly accurately delineated and does not expect that there will be very great changes in the estimated in-place reserves. It does believe, however, that advancing technology, especially in the direction of *in situ* recovery, will increase the proved recoverable reserves. The commercial application of these techniques appears to be some years away and it is not expected that significant production using *in situ* technology will occur in the short term. Commercial development of the surface mineable deposits is on-going but with the recent high inflation and substantial increases in pre-production costs, especially related to interest on capital, manpower requirements and design, several of the potential development projects may be delayed until more attractive economic conditions prevail.

Appendix 1

RESOURCE ESTIMATION

(Part I. Conventional Oil and Gas Resources)

Philosophy

Policies and decisions involved in the stewardship of the nation's resources must be based on the best possible knowledge of the resource distribution in nature. To satisfy this need, an estimating procedure should answer the questions:

1. *How large is the resource?*

2. *Where is the resource located?*

3. *In what size deposits does it exist?*

4. *What is its composition and quality?*

5. *How certain are we of any of these opinions?*

In addition, the estimates must be generated in a form amenable to economic analysis with supply rates being the ultimate objective, which in turn can be related to demand forecasts.

The precise answers to some of these questions can be obtained only after the resource is totally depleted. In the early stages of exploration there is enormous uncertainty but even then finite limits can be set on the possible range of answers. As the exploration process continues and knowledge accrues the range will narrow, rapidly at first, then more slowly. Because the real answers are not attainable, they must be estimated indirectly using whatever information is available.

Decisions under uncertainty are inescapable. The important thing is to quantify and make explicit the uncertainty.

Tenets Underlying Resource Estimation

1. Resource estimates can be made on any level of data.

2. Degree of uncertainty related to an estimate must be identified (and incorporated into any subsequent use of the estimate).

3. The probability of existence and the probable size of deposits should be considered separately.

4. The sizes of resource deposits are approximately log-normally distributed in nature.

5. The eventual discovery of a resource is not a requirement in the estimation of the ultimate recoverable resource.

6. No *a priori* economic considerations should be included in estimations of ultimate recoverable resources.

7. Current and foreseeable technology of recovery is assumed.

1. Resource estimates can be made on any level of data—An opinion, frequently expressed, is that inadequate information exists to make an estimate of the resources of a given region. In the absence of any information at all, this opinion might have some validity. In nearly all cases, however, some information concerning the most gross interpretation of the basin geology exists. Using the principles of oil and gas generation and accumulation from worldwide experience it is possible to make use of subjective judgement with this minimum data to form an opinion or estimate of whether or not hydrocarbon resources are likely to occur. Were it not for this possibility the industry would have no basis on which to base initial exploration decisions. In practice, even in the earliest decisions of whether or not to acquire land and undertake the first exploratory venture in a new basin, intuitive judgement based on years of experience is brought into play before making the decision to expend large sums of money on geophysical or drilling activity. It is true that the task of making estimates is somewhat easier when the data base includes a clear concept of the basic geology, with some measure of the geometric configurations and possibly evidence of the presence or absence of hydrocarbons. The method or approach used in making an estimate will, of course, change as the amount and nature of the available data changes. For example, in early stages, with little data, a gross basin estimate heavily biased with subjective judgement is appropriate. As the data base expands, and the results of geophysical surveys, drilling and perhaps geochemical studies are available, objective data become dominant. The method used in making an estimate may be changed to deal with exploration plays and perhaps progress to making estimates of individual prospects. In practice, with a minimum of data it is possible to make an estimate. In the presence of abundant data, the choice of the method used becomes more dependent on the availability of time and resources. The quality of an estimate is only as good as the geological studies upon which it is based.

2. *Degree of uncertainty related to an estimate must be identified (and incorporated into any subsequent use of the estimate)*—An estimate of the size of a resource without some measure of the certainty with which that estimate is held, is incomplete or constitutes partial information. The reader is unable to infer whether the estimate is intended as an almost certain event, or whether it is a speculation on some remote exploration possibility. The necessity of expressing certainty becomes particularly important where a large range of values exists. For example, reserves are known to exist with a high level of

certainty. At the other extreme in the same sedimentary basin many large untested structures known to exist on the basis of geological or geophysical evidence may present the possibility of very large values of undiscovered potential but having a very low likelihood of occurrence.

A resource estimate for the Western Canada Sedimentary Basin, expressed as a single number could obviously not be compared with a single-number estimate of the resources of Baffin Bay. The two would have totally different meanings, unless attached was the measure of certainty intended by the estimator. One of those estimates, of course, would have been based on an enormous amount of data from over 80 000 wells; in the other case on a very minimal quantity of geophysical data without a single well.

A further reason for expressing estimates in the form of frequency distributions is that different decisions may make use of estimates with different degrees of certainty. For example, a decision on export or a major capital investment such as a transportation system may require estimates having a high level of certainty. On the other hand, the decision to drill an exploratory well could be based on a low level of certainty so long as the operator is prepared to take a high risk as part of his overall exploration plan, presumably with the chance of discovering a large pool. In assigning the degree of certainty to an estimate it is extremely important not to confuse the absence of information with negative information.

3. *The probability of existence and the probable size of deposits should be considered separately*—The presence of coal and oil sand resources in Western Canada is well established. They are discovered resources and estimates of them will be concerned with their ultimate size or quantity. This same consideration applies to discovered accumulations of conventional oil or gas. An estimate of the oil and gas resources of a frontier basin, however, will incorporate an additional and different type of uncertainty—that is, whether or not the resource exists at all. The two questions: *does a resource exist?* and given that it exists, *how large is it?* are fundamentally different and should be treated separately. The question dealing with the probable size of an oil or gas accumulation, given that it exists, deals with the uncertainties of the characteristics that define the size of the trap and the amount of hydrocarbons that could be contained within the trap. The question of whether or not hydrocarbons occur, is concerned with other uncertainties, which include the presence of adequate source rocks capable of generating hydrocarbons, the presence of suitable reservoir rocks and the existence of trapping configurations with adequate seal rocks present when hydrocarbons migrated. The combination of these latter uncertainties relate to the occurrence of oil and gas and is reflected in the exploration "risk". Many estimators either fail to recognize or do not incorporate the question of the uncertainty of occurrence, and deal only with the precision of measurement of a resource, taking for granted that the resource exists. Appreciation of the uncertainty of occurrence or the nature of exploration risk, helps to understand the exploration process.

4. *The sizes of resource deposits are approximately log-normally distributed in nature*—A log-normal size frequency distribution is one in which the logarithms of the values of the variable form a normal or linear distribution. This distribution of sizes is one in which the size progression from largest to smallest changes extremely rapidly, and in which the few largest pools of oil in a set of related occurrences will contain the bulk of the total resource. Typically, 25 per cent of the oil in a basin or in a play may be expected in the largest pool. The second largest pool may contain about 10 per cent, the third 7 per cent, and so on. The first ten pools will contain the bulk of the oil with the remainder in many small pools. Characteristically, the largest pools, which are generally the most evident geologically, are found early in the exploration process. For this reason, estimates of resources should stabilize fairly early in the exploration process after the major plays have been recognized and diagnostically tested. The sizes of additional pools left to be found are then relatively predictable. The early discovered, relatively large pools tend to anchor the probability distribution of estimates.

Because of the log-normality of most types of deposits, economic studies will be primarily concerned with those few large pools in any distribution which will determine the economic viability of the total resource. Once the infrastructure in a region is in place (pipelines, compressors, and so on), smaller pools may also become economic although they would not necessarily be economic on their own. The fundamental log-normality of the pool size distribution has, of course, a strong bearing on the estimates of the total resource.

5. *The eventual discovery of a resource is not a requirement in the estimation of the ultimate recoverable resource*—There is a tendency in making estimates of resources to eliminate some potential deposits because for a variety of reasons they are unlikely ever to be sought or discovered. These reasons may include small size, lack of seismic identity, extreme depth or ice cover, or general difficulty of location. Clearly, the ability to find deposits is not a necessary condition of their existence.

6. *No* a priori *economic considerations should be included in estimations of ultimate recoverable resources*—Potential hydrocarbon resources that may be non-economic today or in the near term must not be excluded from ultimate recoverable resources. The economics of supply are subject to radical change and are not entirely predictable. Conceptually, the technologically recoverable resource must include all the prognosticated potential deposits, recognizing that some portion of the resource may never become an economic reserve. Nevertheless, it is necessary to establish some arbitrary minimum cutoff, well below any foreseeable economic limit, in order to exclude hydrocarbons in tiny accumulations that approach "background" level.

7. *Current and foreseeable technology of recovery is assumed*—In the formulation of estimates of resources, the efficient application of the best existing recovery technology is assumed. This will commonly include application of

enhanced recovery techniques which have become industry norms. Some estimators and economists would prefer estimates of in-place resources but these have little meaning until the recoverable portion is identified.

Having outlined the main requirement of a system adequate for estimating undiscovered resource potential, it is more or less obvious what this system should incorporate. It should incorporate both objective data and subjective judgement retaining the fundamental uncertainties associated with both types of input. The ratio of these two types of input will change as exploration proceeds, thus the system must be flexible. Most of the geological factors considered in preparing an estimate will have a range of possible values at different levels of certainty, rather than a single value. The system must, therefore, incorporate this range and identify the uncertainties. The system must be designed to facilitate systematic revision. Over the past few years, a method has been developed incorporating these characteristics using a probabilistic technique. The details of this method or technique are described in the following section.

Method

The method used to make the estimates presented in this report is designed to operate with whatever data base is available, to incorporate uncertainty and to answer the following questions:

- How much hydrocarbon exists?
- Where is it?
- How big are the pools?
- How certain are the estimates?

An estimate of hydrocarbon potential can be expressed as an equation relating a series of variables to the potential. Two examples are shown in Figure A1. The advantage of an explicit equation is that rigorous scrutiny of variables and assumptions can be made. In general, specific values are unknown for most of the variables in the potential equation. At least some of the variables have a wide range of possible values, and therefore the equation will also have a range of solutions. This range is illustrated in frequency distributions of resource estimates.

The geologic parameters in the equation are described, where necessary, by subjectively derived cumulative distribution functions based on the judgement of the estimators. The parameters are described initially by two probability distributions (conditional and marginal). In discussing porosity for example, the question asked is: *What is the average porosity in a particular unit?* This is really two questions—*Is there porosity in the unit?* (marginal probability) and, if there is, *how much?* (conditional probability). The two questions require consideration of different factors and are best answered separately.

Figure A1. Alternative equations illustrating two approaches to the estimation of potential resources.

POTENTIAL EQUATIONS

VOLUMETRIC TYPE —

Area potential = Volume of rock • Hydrocarbon yield/Unit volume

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EXPLORATION PLAY TYPE —

Prospect potential = Area of trap • Reservoir thk. • Porosity • (1-Water sat.) • Trap fill • Oil fraction • Recovery • Constant

≡ Volume of pores in trap • Hydrocarbon fraction • Engineering factors

The separate probability statements can be combined to provide a joint probability statement that answers the initial question, *What is the average porosity in the unit?*

A conditional probability curve is constructed by questioning technical experts as to the chance of the average porosity exceeding a given value, assuming that the porosity is greater than a cutoff figure. The distribution is anchored at the small end by the cutoff and the maximum value is in part related to the porosity value attainable in sand (45 per cent) discounted to an average value over the reservoir. Where measured values in wells are available they are incorporated. The 5 per cent and 95 per cent probability values are estimated to control the tails of the distribution and the quartile values establish the central part of the distribution. A group of experts produces the curve by either a verbal consensus or by averaging curves drawn individually by the members.

The marginal probability or the answer to the question—*What is the probability that the porosity is greater than a minimum value?*—is given as a single number based on a consideration of available data and using subjective judgement derived from the experts' experience in petroleum geology in general. Clearly the marginal probability could have a range of values and should be entered as a distribution. This has not been done as yet.

The product of the marginal probabilities is the expected success ratio—the chance that a given prospect will contain pooled hydrocarbon (right side of

Figure A2. Data form used in estimating play parameters.

PLAY/PROSPECT										DATE
POTENTIAL EQUATION VARIABLES								"OIL" OCCURRENCE FACTORS		REMARKS
	Conditional probability Per cent GT.							Presence or adequacy	Marginal probability	
	100	95	75	50	25	5	0			
Area of closure	1	10	18	23	26	33	50	Geometric closure	.8	
Reservoir thk.	10			40			90	Lithofacies	1	
Porosity	.08			.12			.16	Porosity	.8	
Trap fill	.05			.4			.7	Seal	1	
Recovery				.35				Timing	.5	
Water sat.				.25				Source	.5	
Shrinkage				.7				Preservation	1	
Gas fraction				.5				Recovery	1	
No. of prospects	3	8	15	20	25	40	60			
										8,000 ft.
										average depth
								Product	.16	

Figure A2). The presence of pooled hydrocarbons depends on the simultaneous occurrence of several factors (see "oil occurrence factors", Figure A2). The marginal probabilities describe the likelihood that these factors occur. Their product describes the likelihood of simultaneous occurrence. The absence of any of these essential factors eliminates the possibility of pooled hydrocarbons. This estimated success ratio can be compared to the estimator's opinion of the uncertainty of the venture.

The form of the "potential" equation is related to the nature of the data being considered. Although there are several equation variations there are two basic types: the "volumetric" type and the "exploration play" type (see Figure A1).

The volumetric approach makes use of analogues to the basin, area or rock unit under consideration, but is usually done at the basin level. Ultimate yield of recoverable hydrocarbon per unit volume of rock is determined for sedimentary basins geologically similar to the basin under consideration. The yield value is multiplied by the volume of the sediments in the basin. The approach is usually inadequate because analogues are not available for many basins and, where they are, reliable yield figures (barrels per cubic mile) are not available. The method is, however, a useful check on the "exploration play" method and, if little data are available, the "volumetric" approach may be the best alternative. It is desirable to describe estimates of the yield and perhaps of the volume by frequency distributions and to incorporate the possibility that the basin may be barren of pooled hydrocarbons.

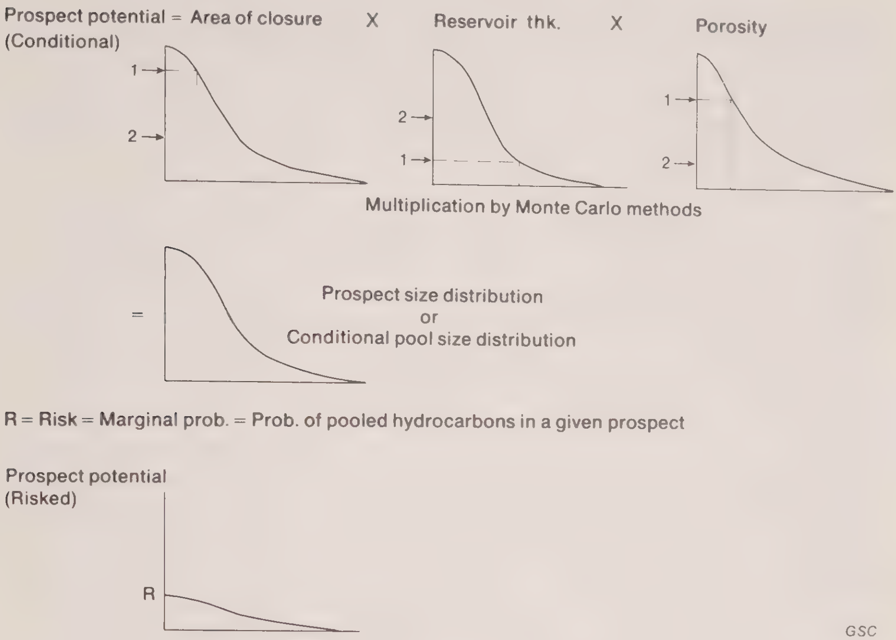
In the "exploration play" approach, estimates are made for individual, demonstrated or conceptual exploration plays in an area. This requires more data than the "volumetric" approach, but answers the question—*What are the sizes of the accumulations present?*—and is more specific as to where the hydrocarbons may occur. Both of these considerations are necessary for economic analysis.

A play estimate is basically the addition of prospect estimates. It is desirable, but generally impossible, to identify all prospects and to estimate their potential individually. What can be done is to produce distributions that describe the range of frequency of occurrence of values that the parameters may have throughout *all* prospects in the play (see Figure A3).

The frequency distribution curves are digitized and entered into the computer and a Monte Carlo technique is used to provide an answer in the form of a frequency distribution of solutions to the potential equation. In the technique, a value from each digitized parameter curve stored in the computer is randomly selected and used to produce one possible solution to the equation. The process is repeated 10 000 times. The distribution of the 10 000 solutions is the distribution of sizes of prospects in the play, or the pool size distribution conditional on pooled hydrocarbon occurring.

The conditional distribution can be "risked" by applying the product of marginal probabilities of the parameters to produce a joint distribution. This

Figure A3. Steps used to estimate the hydrocarbon potential of a prospect.

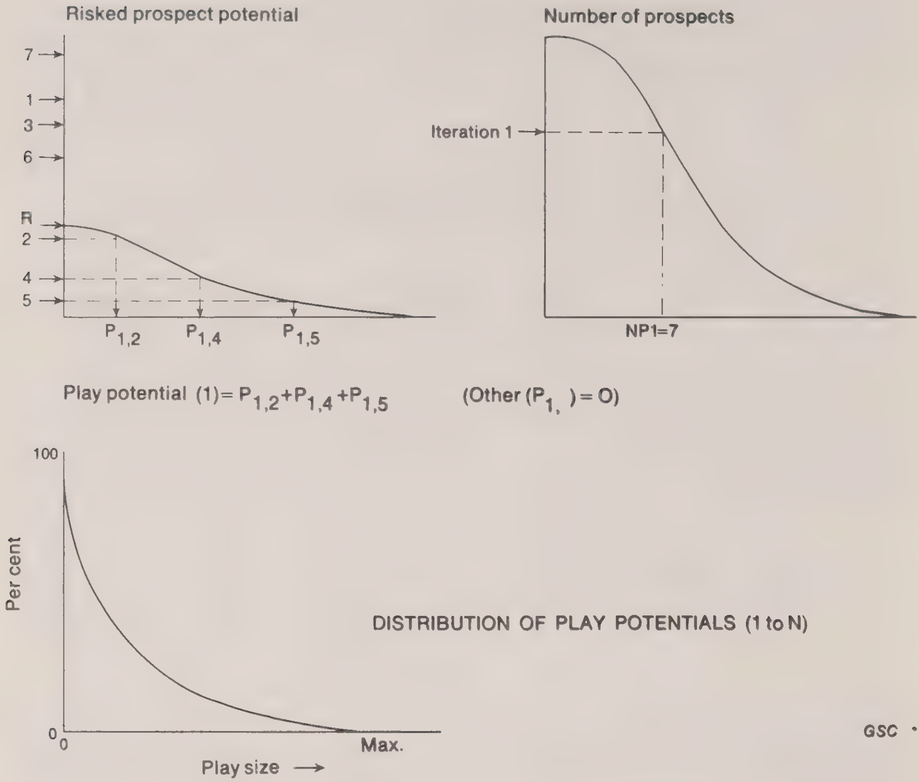


joint distribution (risked prospect potential) now illustrates the distribution of possible pool sizes, along with the probability that some of the prospects will be barren.

The next step in the procedure is to estimate the play potential. At this point, we have a distribution describing the amount of hydrocarbon expected in any given prospect and a distribution of estimates of the number of prospects. The number-of-prospects curve is prepared at the same time as the curves for the various equation parameters (Figure A2). These two distributions are combined, using the Monte Carlo procedure as follows (Figure A4): a value from the number-of-prospects curve is randomly selected (in the example, seven prospects are shown) and that number of pools are randomly selected from the risked-prospect-potential curve. The sizes of the pools selected are summed to give the play potential for that iteration. As shown in Figure A4, some zero values are included. The process is repeated 2 000 times to give 2 000 results from 2 000 possible sets of prospects. The distribution of the results of these 2 000 tries describes the potential of the play in terms of the likelihood of the play containing more than a given number of barrels of oil. If required, the various play potentials are added to give a basin potential.

If the group is not satisfied with the results after going through the estimating procedure, it can then go back to the distributions describing the variables and to

Figure A4. Steps used to estimate the hydrocarbon potential of a play.



the marginal probabilities. In some cases, new ideas or new data are available and rational changes can be made. Often they cannot, and the estimates must be accepted. The facility to critically examine the component parts is crucial in the very necessary reappraisal procedure.

In summary, the exploration play approach to resource estimation is desirable for the following reasons:

- it incorporates uncertainty into the estimates of potential;
- it displays the possible range of estimates;
- it indicates the expected pool size distribution;
- it indicates the general location of the hydrocarbon resource;
- it breaks the assessment procedure into component parts that can be critically examined;
- it provides ease of revision through alteration of the components.

Interpretation and Application

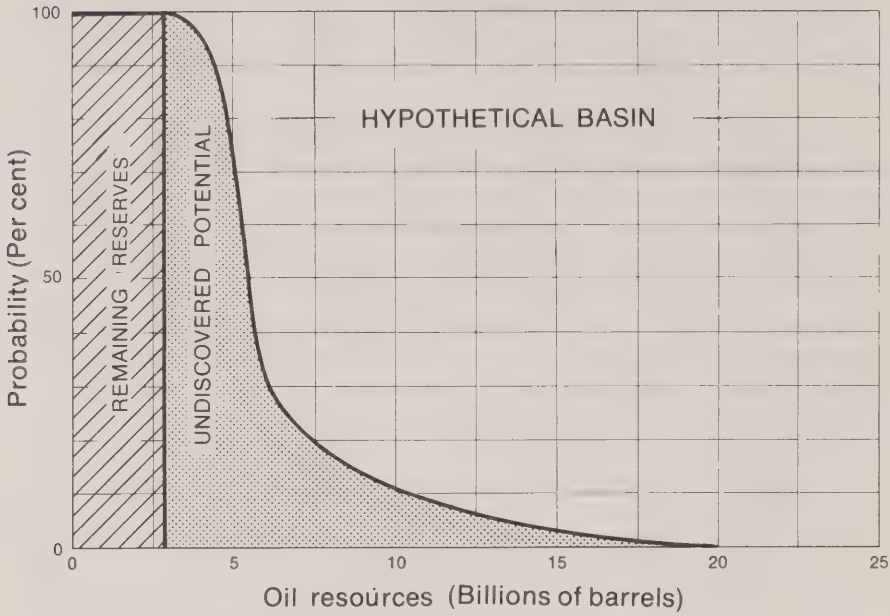
The need for resource estimates, their desirable characteristics and methods of achieving these requirements have been discussed. The estimates that have been produced and are contained in this report are in the form of cumulative frequency distributions. It is appropriate to discuss how to interpret these estimates and how they may be used in economic analysis or formulation of policy.

Figure A5 is a diagrammatic example of an estimate of ultimate recoverable oil resources of a hypothetical basin or play. This curve is drawn in a "greater than" mode. That is to say, it should be read as: there is a 50 per cent probability that the resource is greater than 5.5 billion barrels and there is zero probability that the size of the resource is greater than 20 billion barrels of oil. The curve includes both discovered reserves and undiscovered potential. The curve is a frequency distribution of estimates and may be considered to consist of an infinite number of estimates of the size of the resource. The curve represents the estimator's opinion or belief that the actual size of the resource is within the range 3 to 20 billion barrels, and indicates the likelihood that the actual value is larger than any value within the range. As shown in Figure A5, there is a one hundred per cent certainty that at least as much or greater than the proven reserves exists. The steeper portion of this curve from about a probability of 90 per cent through 30 per cent contains the most frequently occurring estimates and, at a slightly lower probability the arithmetic mean or expected value (6.5 billion at 25 per cent). It is a mistake to ignore that portion of the curve between 30 per cent and 0 per cent probability or the tail of the distribution, because it expresses the opinion that there is a low but finite probability that significantly larger resources may exist. The simultaneous optimum occurrence of all of the important oil pooling factors (excellent source, thick porous reservoir, large trap with favourable timing of migration) leads to the giant accumulations of resources. This is, of course, a rare event.

Although this curve may be considered the expression of an infinite number of estimates, it must be borne in mind that only one real value exists. The estimates reflect the level of knowledge, information and data available at that time. As new data are added and as success or failure is encountered in the exploration process, the estimates may be expected to change. Generally, the range of estimates will be reduced either by delineating proven reserves (100 per cent probability) or by reduction of the maximum value as negative aspects of the play or region become known, that is, as prospects are tested by the drill, found barren and eliminated.

There is a danger on examining a curve of estimates (Figure A5) that the ultimate recoverable resource may be regarded as an economic reserve. If the curve was for a region offshore in the high Arctic then only a portion of the resource could be expected to become an economic reserve. One of the significant factors that determines that portion of the resource that might become an economic reserve would be the size of the accumulations in which the resource exists (the pool size). Clearly, pool sizes that are economic to develop in

Figure A5. Estimate of oil resources for a hypothetical basin (cumulative per cent probability distribution). For this basin there is a 30% probability that the resource is greater than 6 billion barrels and a zero probability that it exceeds 20 billion barrels.



southern Alberta might be totally uneconomic to develop in frontier areas. Recognition of the log-normality of the pool size distribution is of paramount importance in considering what portion of a frontier resource might eventually be considered an economic reserve and ultimately become a part of the future supply. There appears to be a relatively predictable per cent of the total resource in the 1st, 2nd, 3rd.......nth sized pools. The nature of the log-normal distribution is such that the bulk of the resource, usually greater than 50 per cent, will be found in the few largest pools in any play or for that matter in any basin. Assuming that these larger pools were the only economic ones, then about 50 per cent of the ultimate resource might fall into the economic category.

Although resource-estimate curves can be used in a qualitative sense, for quantitative studies of supply an economic discount must be applied to this curve to produce another describing the economically exploitable part of the resource. Programs are currently being developed which will enable the economically recoverable portion to be estimated using the estimates of recoverable resources.

Estimates of the rate of supply are the ultimate objective, but the resource-estimate curves have considerable value and provide useful information. For example:

1. The curve's range and configuration reflect the current level of knowledge or understanding of the exploration play or region.

2. The maximum value identifies the highest expectations for a play, basin or a region; for example, it may indicate that a particular area should not be expected to be an important source of hydrocarbon.

3. The resource curves allow others to view the exploration opportunities and "risks" through the eyes of industry who make similar estimates both in this form and intuitively in their thinking. It should be recognized that the exploration industry is not necessarily interested in looking for the most likely quantities, suggested by the steeper parts of the curves, but are exploring in frontier basins on the chance that large quantities of petroleum suggested at low probability levels actually occur.

4. A valuable attribute of this type of display is that the decision-maker does not have to use the same number for all types of decisions, but may select a probability level appropriate to the particular decision. For example, in dealing with questions of export or large economic commitments, one would tend to consider the higher probability ranges close to certainty. On the other hand, for exploration decisions the low probability ranges of the curves may be used because the larger the possible return, the greater the risk that may be acceptable.

5. If a planner, concerned with energy supply, wishes to compare resource potentials of different commodity types—for example, uranium, coal and oil sands with conventional oil—then he could make more valid comparisons by using the same probability ranges for the various commodities.

6. The skewness of the curves and the range of estimates indicate degree of uncertainty. The source of this uncertainty is identified in the estimating procedure. This information can be used to guide planning in research and development.

Appendix 2

GLOSSARY OF TERMS

Basement: The barren crust of the earth below sedimentary deposits that have petroleum potential.

Conventional oil and gas: Oil and gas wholly or in part recoverable from a well using standard techniques.

Dry gas: A natural gas consisting almost entirely of methane, with only traces of heavier liquid hydrocarbons.

Exploration play: A group of similar exploration prospects postulated or proven to contain oil and / or natural gas, i.e. a group of generically related prospects or pools. A play can contain both discovered pools and conceptual prospects as yet undrilled.

Frontier areas: Remote areas beyond those where exploration has resulted in the production of oil and gas, e.g. offshore areas of Canada, the Arctic Islands and the Mackenzie Delta-Beaufort Sea.

Geochemistry: The study of the chemistry of the earth's crust. In this report, refers to organic geochemistry or study of organic material in sedimentary rocks and petroleum generated from it.

Geophysical logs: Records obtained by lowering geophysical instruments into boreholes and recording continuously some physical property of the rocks.

Geothermal gradient: The rate of increase of temperature with depth in the Earth.

Heavy oil: A high-viscosity, high-gravity crude oil that is difficult to recover at the surface.

Hydrocarbon: An organic compound (gaseous, liquid or solid) consisting solely of carbon and hydrogen.

Impermeable: The condition of a sediment or soil that renders it incapable of transmitting fluids under pressure.

Liquid hydrocarbon: Crude oil and natural gas liquids.

Natural gas liquids: Hydrocarbons generally produced in association with natural gas, and recoverable as liquids, including propane, butanes, and pentanes plus.

Permeability: The capacity of a porous rock to transmit a fluid.

Petroleum: The whole spectrum of hydrocarbons including gases, liquids and solids.

Pinchout: The termination or end of a thinning layer of rock sandwiched between other rock types (i.e. a porous sandstone into impermeable shale).

Porosity: The amount of void space in a rock. In quantity porosity is expressed as percentage of the total volume of a rock or soil occupied by interstices.

Prospect: A geological configuration (e.g. a structure defined geophysically) conceived to have trapped petroleum that forms a target for drilling.

Reef: A ridge- or mound-like, layered sedimentary rock structure built by and composed of the calcareous remains of sedentary organisms.

Reservoir: A subsurface trap which contains an accumulation of crude oil, natural gas or water.

Reservoir rock: Any rock with adequate porosity or fractures to permit liquid or gaseous hydrocarbons to be contained.

Salt pillow: Embryonic salt dome rising from its source bed.

Sandstone: A sedimentary rock consisting of sand grains more or less firmly united by some cement (silica, iron oxide or calcium carbonate).

Sedimentary basins: A topographically low area in which sediments accumulate.

Shale: Fine-grained, detrital sedimentary rock formed by the consolidation of clay, silt or mud.

Specific gravity: The ratio of the weight of a given volume of a substance to that of an equal volume of another substance (e.g. water) used as a standard.

Synthetic crude: A semi-refined hydrocarbon generally derived from naturally occurring bitumen.

Tectonism: A general term for all movement of the crust produced by Earth forces.

Trap: The accumulation of petroleum in a reservoir rock sealed by impermeable rock so that migration and escape is prevented.

Unconventional oil resources: Hydrocarbon that cannot be produced using conventional means; the Alberta oil sands are the best known.

Up-dip: A direction that is upwards on an inclined surface.

Volumetric approach: A technique used to estimate the hydrocarbon potential of an unknown area. The volume of potentially oil- or gas-bearing sedimentary rocks in the area is calculated, and then compared to a similar producing basin of known richness in hydrocarbon content.

Wildcat well: An exploratory well drilled for oil or gas on a geologic structure without detailed geologic information.

Abbreviations

EMR: Department of Energy, Mines and Resources.

NEB: National Energy Board.

CPA: Canadian Petroleum Association.

NGL: Natural gas liquids.

bbl: barrel.

Btu: The amount of heat needed to raise the temperature of one pound of water 1°F.

Mcf: one thousand standard cubic feet.

Tcf: one trillion (one thousand billion) standard cubic feet.

psia: pounds per square inch absolute.

MMstb: million stocktank barrels.

Bstb: billion stocktank barrels.